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AIR CONSTRUCTION PERMIT APPLICATION
BIOMASS GAS & ELECTRIC (BG&E)
TALLAHASSEE RENEWABLE ENERGY CENTER

Submitted to:

Florida Department of Environmental Protection

Submitted on behalf of:

BG&E of Tallahassee, L.L.C. (d/b/a Biomass Gas & Electric of Tallahassee)
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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPLICATION FORMS

APPENDICES

1.0 INTRODUCTION

To improve domestic energy sources and to address global climate change issues, the State of Florida is encouraging the expanded use of *biomass-based* energy, both for transportation needs and electrical generation. Governor Crist's Action Team on Energy and Climate Change has recommended that the State expand its biomass-based energy sources, citing several benefits including economic development, energy security, fuel diversity, and reliability as well as helping the State achieve its greenhouse gas (GHG) emissions reduction objectives. Biomass (which is a broad term covering various types of non-fossil organic material, such as agricultural crops and byproducts, landscape and yard trimmings, logging and lumber mill residues, untreated wood materials, etc.) is relatively abundant in Florida as well as the southeastern U.S., and is a proven, reliable source of renewable energy which can be considered carbon-neutral.

Biomass can be combusted in a traditional boiler to produce electricity, or biomass can be processed to form either a gas or a liquid "biofuel" that can then be used efficiently in a boiler or a combustion turbine. Biomass Gas & Electric of Tallahassee, L.L.C. (d/b/a Biomass Gas & Electric of Tallahassee), or BG&E, a new electricity provider in Florida, is proposing that the Tallahassee Renewable Energy Center power project (the Project) generate "product gas". Specifically, biomass will be gasified, and the product gas that is produced will be combusted in energy-efficient, combined cycle combustion turbines to produce electricity. The proposed project will generate a nominal net 42 megawatts (MW) of electricity.

Biomass gasification units such as the ones being proposed by BG&E represent an excellent opportunity for the State by providing a reliable, renewable energy source, as well as helping to curb the State's GHG emissions. In addition, projects such as this will help Florida's utilities meet Governor Crist's Executive Order No. 07-027, proposing a 20 percent renewable energy requirement.

This application contains the information required by FDEP Form No. 62-210.900(1), Effective: 3/16/08, Application for Air Permit – Long Form. This air application report is divided into the following major sections:

- Section 1.0 provides the Project introduction;
- Section 2.0 presents a description of the Project;

- Section 3.0 provides a description of individual emission units and controls;
- Section 4.0 provides a review of the air requirements applicable to the Project; and
- Attachment: FDEP Form No. 62-210.900(1), Application for Air Permit – Long Form.

2.0 PROJECT DESCRIPTION

BG&E of Tallahassee, LLC, d.b.a. Biomass Gas & Electric of Tallahassee, is proposing to construct a biomass-based electrical generating power plant at the Florida State University in Tallahassee Florida. The proposed project will generate a nominal net 42 megawatts (MW) of electricity. Construction is proposed to commence in September 2008, with a proposed in-service date of July 2010.

The project consists of a biomass fuel “wood chips” delivery/ handling system, a biomass gasification system, a biomass dryer, a gas cleanup system, two gas combustion turbines, two heat recovery steam generators (HRSG) with duct burner firing, condensing steam turbine generator, an auxiliary natural gas fired package boiler for start-up use only, an emergency flare system, cooling towers, and auxiliary support equipment such as air systems. The biomass fuel “wood chips” will be chipped to size and screened at a remote location. The fuel preparation process will be owned and operated by others. Biomass fuel will be delivered using approximately 100 railroad cars per shipment to the power plant. Anticipated fuel delivery frequency is one shipment every 7 to 10 days. All fuel deliveries will be by railroad and there are no provisions in the project to receive fuel by truck or other methods.

At the power plant, the railcars will be unloaded into a pit located under a new railroad siding where the fuel is conveyed, via a covered belt conveyor, to the fuel storage building. The fuel storage building will contain 10 to 14 days of fuel storage. The storage building will be under roof with the sides of the storage being open.

From the fuel storage building, the fuel will be conveyed to a dryer where the moisture is reduced from as high as 37 percent to approximately 23 percent. Leaving the dryer, the fuel will be conveyed via a covered conveyor system to the gasification process area where it is stored in a metering/storage bin. Approximately 730 tons per day (dry basis) of biomass will be fed to the gasifier.

In the gasifier, product gas is formed from the introduction of biomass fuel, which is rapidly pyrolyzed in an oxygen-starved environment by hot sand (olivine). During this process, the olivine temperature diminishes, while the breakdown of the fuel results in the production of char particles (carbon), product gas and a small amount of condensable organic compounds (tars). The resultant char and olivine are separated from the gas stream exiting the gasifier in dual, two-stage gasifier cyclones. The olivine and char are recirculated to the combustor where the char is burned and serves as a fuel source to reheat the circulating olivine. The reheated olivine is then transported back to the gasifier to supply the energy necessary for the gasification of the incoming wood feedstock.

Flue gas from the combustor flows through an additional cyclone, heat recovery exchangers and a baghouse before exhausting to the atmosphere. Product gas from the gasifier is directed to the gas clean-up system for removal of impurities prior to utilization in the two Solar Model T-130 combustion turbines (CTs). The CTs will produce 29.0 MW at an average atmospheric temperature of 59° F. Exhaust gases from the CTs will pass thru two heat recovery steam generators (HRSG's) equipped with duct burners (DBs) to generate high-pressure steam. Product gas is also used to fire the two DBs. The high-pressure steam generated using the HRSG's will be piped to a steam turbine generator to produce 20.7 MW at an average atmospheric temperature of 59° F. The parasitic electrical loads are estimated to be 8.3 MW. Therefore, the net electrical power available at an average atmospheric temperature of 59° F is 41.4 MW. The typical product gas composition is provided in Table 2-1.

2.1 Description of Emission Units

The following sections provide a more detailed discussion of the processes and emission units associated with the BG&E of Tallahassee Project (the Project). The project location and site map is provided in Figure 2-1. A proposed project site layout is presented in Figure 2-2. A process schematic of the entire process, from delivery of feedstock to the power generation block, is provided in Figure 2-3, highlighting the emission points. Finally, Figures 2-4 and 2-5 provide more in-depth diagrams of the material handling and gasification processes, respectively.

2.1.1 Material Handling System Description

The feedstock material handling process is depicted in Figure 2-4. All woody biomass will be delivered to a remote fuel preparation area. At this remote area, the feedstock will be sorted, screened and chipped to size. Deleterious material such as nails, glass and metal will be removed for landfill disposal. The wood feedstock moisture content will be between 30 percent and 40 percent. The fuel preparation process will be owned and operated by others. Prepared woody biomass feedstock will be delivered to the gasification site by rail.

The feedstock delivery system to the site will consist of bottom discharge double collection hoppers for receiving processed wood chips from railroad cars. Each rail car has a capacity up to ~ 7,000 cubic feet (cf), with the feedstock density estimated at ~ 17 lb/cf (@ 30 percent moisture), for a total of ~ 80 to 90 tons per rail car. The railroad cars will be positioned over the receiving hoppers and the car hopper gates will be opened, allowing the chips to be discharged from them (Figure 2-4, point BC-1). The hoppers will have an integral dust collection system to collect dust that may be discharged from the top of the hoppers during the unloading process. From the bottom of the two collection hoppers, the wood chips will be transferred to a collecting belt conveyor via vibratory feeders which are enclosed (BC-2). A dust collection system will collect dust at the transfer point from the discharge chutes to the unloading reclaim conveyor.

From the railcar unloading reclaim conveyor, the material will be conveyed to the material storage building via belt conveyors. Detectors will be installed on this conveyor to remove deleterious material from the material stream prior to stockpiling the fuel. The fuel storage building will contain 10 days of live storage, and will be stockpiled using an automated stacker/reclaimer which receives material from a ground level conveyor inside the building during stacking, and returns the fuel to the same belt conveyor during reclaiming activities. The feedstock will be evenly distributed in piles up to an average of 10 feet high. The fuel storage building will contain 10 to 14 days of fuel storage. The storage building will be under roof, with the sides of the storage being open. Approximately 1,000 wet tons per day of wood will be received (based on 30 percent moisture), which will produce 730 tons per day feed to the gasifier (dry basis).

From the fuel storage building, the fuel will be conveyed to a dryer (BC-3 and BC-4) where the moisture is reduced from as high as 37 percent to approximately 23 percent. Belt conveyors will then transport the feedstock to a 12-hour storage silo adjacent to the gasifier (BC-5). The belt conveyors will be equipped with belt covers to protect the material from the weather and to prevent the wind from blowing material off of the conveyor belt during transport to the storage silo. Material will be reclaimed from the storage silo via an internal screw discharger, which will deposit the material on a belt conveyor contained primarily inside the silo structure. This belt conveyor (BC-6) will transfer the wood fuel to a vertical elevator that will discharge the fuel via an enclosed chute system to the gasifier fuel feed bin. Approximately 730 tons per day (dry basis) of biomass will be fed to the gasifier. All transfer systems from conveyor to conveyor employ totally enclosed head boxes, chutes, and skirtboard systems to contain the fuel and any dust that may be produced at the transfer points. Particulate emissions from these transfer points are kept to a minimum through special designs. The feed bin has a bin vent on top of it to filter out the exhaust produced from transfer of wood into the bin through a rotary valve.

2.1.2 Gasifier System

Figure 2-5 provides a schematic diagram of the gasification process. Due to the claim of confidentiality, this figure has been provided under separate cover. The gasifier, combustor, gas clean-up system, cyclones and baghouse are the primary equipment components of the gasification process. Within these components, circulated olivine, a sand-like material is used as a heat transfer medium to support the reactions occurring in the gasifier and combustor. In addition, there are small natural gas-fired start-up burners associated with the gasifier and combustor. These small burners are more fully described in the section addressing startup emissions. It is estimated that there will be approximately 6 startups per year and that the amount of natural gas to be fired will be minimal, at less than 5 percent of total operating hours.

2.1.2.1 Gasifier

In the gasifier, product gas is formed from the introduction of biomass fuel, which is rapidly pyrolyzed in an oxygen-free environment by hot olivine. Steam is used in the gasifier to provide assist forced air which provides the initial conveying medium to begin olivine circulation through the system. Olivine recirculation starts when the vessel temperature has reached approximately 800 °F. The recirculating olivine provides the majority of thermal energy to heat up the gasifier. The gasifier must be heated to at least 1,300 °F prior to the introduction of wood so that the pyrolysis reactions can take place without producing excessive amounts of tar. Once these reactions begin, the resulting product gas provides the primary motive force for the conveying of the olivine and char through the gasifier vessel. Air is gradually reduced once wood feed has started, and is completely turned off once 1,300 °F is reached.

During this process, the olivine temperature diminishes, while the breakdown of the fuel results in the production of char particles (carbon), product gas and a small amount of condensable organic compounds (tars). The resultant char and olivine are separated from the gas stream exiting the gasifier in the dual two-stage gasifier cyclones. Product gas from the gasifier is directed to the gas clean-up system for removal of impurities prior to utilization in the two Solar Model T-130 combustion turbines (CTs). The product gas contains hydrogen sulfide, which is scrubbed out downstream in the gas clean-up system, using an aqueous scrubber. The formation of hydrogen sulfide in the gasifier, in effect, minimizes the amount of fuel sulfur that subsequently enters the combustor.

2.1.2.2 Combustor

At the gasifier exit, the product gas is separated from the olivine and unpyrolyzed char. The char, which is separated out with the olivine in the cyclone, is carried into the combustor. The char contains pyrophoric carbon at 55 percent by weight, 5 percent hydrogen, and 40 percent ash. Air is introduced into the combustor to support the combustion of the char particles with the resultant release of thermal energy, providing additional heat to the recirculating olivine. The reheated olivine is then transported back to the gasifier to supply the energy necessary for the gasification of the incoming wood feedstock.

The combustor cyclone separates the olivine from the flue gas and ash before sending the olivine back to the gasifier. The efficiency of the combustor cyclone is greater than 99.9 percent removal, so that the loss of olivine from the entire system is minimized. The flue gas, smaller ash and traces of fine olivine particles remain entrained in the gas and proceed to the ash cyclone. Due to the very high efficiency of the combustor cyclone, the targeted ash removal efficiency of the ash cyclone is ~ 85 percent. The ash cyclone is followed by a baghouse, which removes >99 percent of the remaining particulate before exhausting to the atmosphere.

It is important to note that the flue gas from the combustor contains very little sulfur, as the organic sulfur remains in the product gas as hydrogen sulfide. This is because the pyrolysis process in the product gas gasifier operates in a reducing environment in the absence of oxygen. As a consequence, organic sulfur compounds in the wood decompose into hydrogen sulfide. This component of the gas stream is ultimately eliminated in the product gas clean-up system.

Ash, essentially wood ash, is a waste byproduct of the gasification process and must be continuously removed and disposed of off-site as a non-hazardous solid waste. In addition, it is estimated that about 300 lbs of makeup olivine may be required per day. It is currently proposed that olivine be delivered by truck, and unloaded pneumatically into a storage silo. The silo would be equipped with a baghouse for particulate control. However, it is possible that the use of super sacks may be as efficient and less costly than a pneumatic unloading system. Final details will be provided when available.

2.1.3 Gas Clean-up

Product gas from the gasifier, after exhausting through several cyclones, is directed to the gas clean-up system. Tar is formed in the gasifier and includes a wide spectrum of organic compounds consisting of several aromatic rings. Tars are often categorized as “heavy” and “light” tars. The gas clean-up system is designed primarily to remove these tars from the product gas, after exiting the gasifier and before going to the combustion turbines, but also includes components for removal of other impurities. These include:

- Particulates;
- Organic impurities (tars mentioned above);
- Inorganic impurities, such as NH_3, HCl, H_2S; and
- Volatile (alkali) metals

The clean-up system will first remove the dust particles at temperatures > 400 deg C to avoid condensing tars and water. Cyclones will be used to remove these dust particles. Tars are removed next at temperatures above the water dew point. Inorganic impurities can be removed in an aqueous scrubber.

Tar removal is accomplished in a two-stage scrubber utilizing a special scrubbing oil. The heavy tars are removed in the first scrubber, condensed, separated from the scrubbing oil and recycled to the combustor. The light tars are similarly scrubbed with a different scrubbing oil. The light tars are separated from the scrubbing oil and also recycled to the combustor. Recycling of the tars to the combustor contributes to the energy efficiency of the gasification process and further reduces potential NOx emissions from the combustor. This is due to the tendency of the tars to preferentially react with oxygen, rather than nitrogen in the combustion air. Finally, NOx is further minimized by the manner in which the fuel bound nitrogen is converted to ammonia (NH_3) rather than NOx in the gasifier. As stated earlier, ammonia is one of the inorganic impurities ultimately removed from the product gas in the gas cleanup system.

After the typical impurities have been removed from the product gas, a small slipstream of the gas is further processed in a pressure swing adsorption unit to remove carbon dioxide, thereby concentrating the hydrogen fuel content. Special adsorptive materials are used to preferentially adsorb the target gas species at high pressure. The process then swings to low pressure to desorb the adsorbent material. A concentrated hydrogen gas stream will be produced and transported by pipeline for use by the Florida State University (FSU) research facilities. The off-gas from this process will be blended with the product gas and sent to the power generation unit as a fuel.

2.1.4 Power Generation

2.1.4.1 Gas Turbines

The power generation component of the Project is a biomass-fired 42 MW (net) combined cycle generation facility. The combined cycle system will be fired with a product gas derived from wood waste biomass through the proprietary gasification process discussed earlier. Power will be generated by two Solar Model T-130 combustion turbines (CTs), with a maximum heat input of 145 MMBtu/hr (LHV) for each CT when firing product gas (100 percent capacity, 59°F). The two gas turbines will produce approximately 14.8 MW each. The projected heat rate for the power generation facility, including the product gas process, is estimated at 7,200 Btu/kW-hr.

A start-up compressor will be provided to supply high pressure natural gas to start up the gas turbines. As stated earlier, it is estimated that there will be approximately 6 startups per year. Therefore, no more than 750 hours of operation on natural gas are requested per year. The gas turbine fuel feed will be switched over to product gas when the turbines are operating in a stabilized condition. Product gas from gas cleanup at approximately 110^{o} F and 10 psig will be split to the two compression and gas turbine trains. The product gas will be compressed in a two-stage compressor to feed each gas turbine.

2.1.4.2 Duct Burners (DBs)/Heat Recovery Steam Generators, HSRG

Each of the gas turbine exhaust streams will be routed to a dedicated HSRG, to recover the energy in the gas turbine exhaust stream. Steam generated in the two HSRG units will be combined with steam generated in the gasifier island and sent to a steam turbine generator. Duct burners within each of the HSRG units (rated at ~28 MMBtu/hr each) will be started up with fuel from a slip-stream on the product gas compressor. The exhaust from each HSRG is routed to a selective catalytic reduction (SCR) system for NOx removal and then to a stack for discharge to the atmosphere.

Aqueous ammonia is added to the SCR for the NOx removal reaction. Aqueous ammonia will be delivered by rail car. The rail car storage vessel will remain onsite until a replacement is needed. There will be negligible ammonia emissions from rail car breathing losses.

2.1.4.3 Steam Turbine

The high-pressure steam generated using the HRSG's will be piped to a steam turbine generator to produce approximately 20.7 MW at an average atmospheric temperature of 59° F. Additional onsite power will be required for the power island and for compression, as well as for product gas cleanup, the gasifier process and the fuel yard. The parasitic electrical loads are estimated to be 8.3 MW. Therefore, the net electrical power available at an average atmospheric temperature of 59° F is approximately 41.4 MW.

2.1.5 Utilities and Infrastructure

2.1.5.1 Auxiliary Boiler

A natural gas-fired auxiliary boiler will provide steam as the start-up conveying medium to begin olivine circulation through the gasifier. The steam also aids in increasing the gasifier temperature to 400 deg F so olivine circulation can be started. Additional steam will be used to preheat the steam turbine generator during start-up. The boiler, rated at approximately 62 MMBtu/hr, will be operated for less than 500 hours per year.

2.1.5.2 Cooling Tower

Cooling towers will be required for the steam turbine and for the cooling of compressor gases. The wet surface air condenser (~ 7,050 gallons per minute [gpm]) is the condenser for the steam turbine provided in the project and employs a different technology than a traditional surface heat exchanger (condenser) and cooling tower. The traditional steam turbine heat exchanger (condenser) and cooling tower employ a two-stage method for condensing the steam for both latent and sensible heat rejection. The wet surface air condenser uses one stage that is latent heat rejection. This provides a closer approach to the wet bulb temperature than other methods and is more thermally effective. The air is drawn over the surface of the steam condenser tubes which are sprayed with recirculating water.

In a traditional cooling tower, such as the one to be used for cooling of compressor gases, the cooling water is sprayed onto surfaces and cooled by evaporation of air drawn across the surfaces. This water (~ 3,800 gpm) is then used in a heat exchanger to cool or condense the fluid. The mechanics of the two different types of equipment account for the difference in their drift rates. Particulate emissions from each of the two cooling towers will be controlled by specifying drift eliminators that will result in a low drift rate (0.002 and 0.005 percent drift, respectively).

2.1.5.3 Flare System

A safety vent and flare system, located downstream of the heat recovery section of the gasification plant, provides a means for emergency venting of the product gas to a flare. There are three operating conditions under which the flare system may potentially be needed: startup, planned shutdown and emergency shutdown (i.e., in the event of a gasifier trip). The flare system is provided with a pilot fuel to continuously operate the flare pilots. The large combustion chamber in each of the two flares provides a stable environment to burn the gas produced during process upsets.

2.2 Proposed Operating Modes

2.2.1 Startup and Shutdown Modes

The expected startup and shutdown procedures for the Project are presented in the following paragraphs. The procedures address operation of two separate components of the Project: 1) the gasification process and, 2) the power block. A full description of the procedures is not provided here, as it contains much proprietary information not germane to air emissions. A summary of estimated annual emissions from startups and shutdowns is presented in Table 2-2.

2.2.1.1 Gasifier Operation

Emissions vary depending on whether the system is in start-up, normal operation or shutdown mode. The modes are discussed individually in the following paragraphs.

Start-up. During start-up, gasifier offgas is routed to the flare. The gasifier and combustor systems are heated to the desired temperature using natural gas-fired burners. The combustor burner is rated at 17 MMBtu/hr and the gasifier burner is rated at 25 MMBtu/hr. Sparging and fluidizing flow is started to begin circulating sand and to bring the sand inventory to the desired temperature. As wood feedstock flow is started, the burner duty is reduced. When the gasifier is in a partial oxidation mode, the gasifier air flow is reduced as the gasifier reaction provides the gas velocity required for sand circulation. Steam flow and feedstock flow are ramped up to design rates to avoid overheating. When steam and wood rates have stabilized and the oxygen content in the produce gas is near zero, the product gas can be rerouted from the flare to the gas clean-up system.

Shutdown. There are two shutdown scenarios:

- Emergency shutdown for power outage
- Routine Shutdowns for annual turnarounds and unanticipated, but orderly short shutdowns

The routine shutdowns are of two types:

- Short shutdowns followed by “hot” starts, where the refractory lined vessels and ductwork remain hot and do not require slow heat up rates;
- Longer shutdowns, where the refractory lined vessels and ductwork cool down to the point where slow reheating is required. This typically will happen twice a year, with refractory rework part of the list of tasks to be performed during the shutdown.

Estimates of emissions for shutdowns are done only for NO_x and PM, since the emissions for the other constituents, such as VOC and SO_x are already very low.

Emergency shutdown is defined as total loss or shutdown of incoming electrical power, so that all the process motors stop in a few seconds. Another term used to describe this is an emergency electrical trip. Emergency backup electrical power will be available to provide electrical power to the process control system, and a limited number of other electrical users. In general, gas flow through the plant will ramp down rapidly to zero in a space of 3 to 4 minutes.

An integral part of the emergency shutdown system is the inert gas purging system. This system provides for storage of five times the volume of the gasifier and its associated cyclones. Upon an emergency trip, the product gas will be routed to the flare for several minutes, until the flowrate of gas drops off to essentially zero. At this point, the inert gas system is activated by the emergency electrical power system, and forces an inert gas through the gasifier and its cyclones in sufficient volume that any combustible gases in the vessels are reduced in concentration. The reduction in the concentration is sufficient to dilute the combustible gases below their lower explosive limit in an ambient air environment. An ancillary aspect is to reduce the concentration of oxygen in the gasifier equipment to a level where it will not support combustion, which is nominally below a 5 percent by volume concentration.

Typically, the inert gas system will contain nitrogen at elevated pressure in the gaseous state, so that the full volume of the inert gas system can be charged through the gasifier and its associated equipment in less than one minute. Specifics on this system are currently the subject of preliminary engineering design. Such an emergency shutdown has an unknown frequency of occurring, since it can be tripped by natural phenomena such as a thunderstorm.

For an emergency shutdown using inert gas, the gas should be flared to purge the system of flammable gases. During the initial part of the flaring, there will be a substantial flow of flammable gas to the flare, followed by a rapid decrease in the rate of burning flared gas as it is displaced by inert gas. There will be some continued production of gases and pyrophoric char in the gasifier after the initial purging of the vessels with inert gas. Continued purging with sparge gas – inert gas with less than 5 percent oxygen - will be performed, and the CO and CO_2 levels monitored. The drop in the CO and CO_2 levels to steady, low levels will indicate that the residual materials in the gasifier that could burn, have been burned out by the sparge gas.

Routine shutdowns will generally occur more often over a year than emergency shutdowns, and are planned in advance and thus are orderly. These are short shutdowns that do not require cooling of the refractory vessels. Duration can be from minutes to a number of hours. The basic sequence for the gasifier is:

- Prepare system for shutdown by reducing wood flowrate to 50 percent of design rate.
- Start the gasifier blower, opening the bypass to minimize initial airflow into the gasifier.
- Turn off the wood flow, and monitor the product gas flowrate, and CO and CO_2 composition of the product gas.
- Gradually increase the gasifier blower airflow to the gasifier, using the CO and CO_2 levels to determine when all the wood and carbon have been burned out of the gasifier.

- At the same time, gradually reduce the steam flow to the distributors until it is reduced to zero.
- Maintain an upward adequate airflow velocity during the transition from steam to air.
- Stop airflow to the gasifier when the CO and CO_2 levels indicate all the carbon has been burned out of the gasifier.

The combustor has no sequence; airflow is maintained at the full design flowrate to ensure fluidization. The combustor blower is turned off when the gasifier blower is turned off.

Wood NO_x emissions during the shutdown will occur for a 3 to 4 minute period while the wood is being burned out with air. For 3 minutes, the amount of wood will be at 50 percent of the feedrate, which is about 30,000 lb/hr, or 500 lb/minute. Under the worst case conditions mentioned in AP-42, of 33 lb/hr NO_x per ton of feedstock (Table 1.1.3 in AP-42, for a bituminous cyclone furnace), the NO_x emissions thus could be as high as 8.25 lb/minute. For three minutes, this results in about 25 lbs of NO_x. Assuming four such shutdowns during the year, the NO_x emissions from the wood will be on the order of 100 lb/yr (0.05 tpy).

PM emissions from olivine may occur during this period from the gasifier, since the circulation of olivine will still be occurring, although at reduced rates. Determining the exact amount of PM emissions during the routine shutdown is a complex calculation. However, if it is assumed that the entire amount of olivine in the system inventory is lost out the flare stack during this period, the maximum potential loss can be calculated. Attrition tests have indicated that the attrition loss of olivine from a recirculating olivine system is about 0.1 percent of the total inventory over a 120 day operating period. Since the amount of time for the turnaround shutdown and cool off will be at most one day, the total amount of olivine which could be lost during a single day is on the order of 0.1 percent/120 or 0.0008 percent of the olivine inventory. The inventory is estimated to be on the order of 30,000 lbs. An 0.0008 percent loss results in 0.24 lbs. The actual amount should be less, since the recirculation of olivine will not go on for a full day.

For turnaround shutdown, the sequence here is the same, except that the gasifier and combustor blowers remain on to help cool down the equipment faster. Their flow rates are reduced to where the cooling rate on the refractory is less than 100° F/hr. There is no fired equipment used during this final period, so there are no NO_x or VOC emissions from combustion. The emissions will be about the same as listed above for wood NO_x emissions.

Since there are two turnaround shutdowns per annum, the NO_x emissions from the wood during turnaround shutdown should be no more than about 50 lbs/yr, and in all probability will be less than one-half that amount. PM emissions from olivine may occur during this period from the gasifier, since the circulation of olivine will still be occurring, although at reduced rates.

Since the turnaround shutdown will go on for a much longer period than a routine shutdown, the amount of emissions expected should be higher. However, the estimate already developed assumes that all the olivine is lost, and it uses a 24 hour period as a basis. This is so conservative that this approach is reused to estimate the amount lost during the turnaround, then increased by a factor of 10 to consider the longer period of time the turnaround shutdown runs its blowers. The inventory was estimated to be on the order of 30,000 lbs. An 0.0008 percent loss results in 0.24 lbs. Multiplying this by ten yields 2.4 pounds or, for two annual turnarounds, 5 pounds per year.

Therefore, based on the startup and shutdown procedures described above, it is requested that up to 4 hours of allowable excess emissions be provided in a 24 hour period to address anticipated emissions during startup and shutdown events.

2.2.1.2 Power Block Operation

Emissions calculations for the startup and shutdown emissions from the power block, as well as the gasification operation are presented in Table 2-1. The start-up and shutdown sequencing required for the biomass gasification combined cycle operation will require an excess emission allowance greater than two hours provided under the FDEP rules. During cold start-up, the operating load of the CTs is limited by the amount of steam that can be accepted by the steam turbine and will result in excess emissions. The excess emission allowance requested for the power block is similar to that of other combined cycle projects, with the exception that this is a gasification process. The proposed condition for power block follows:

> *"Excess Emissions Allowed from Combined Cycle Combustion Turbines: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.*

a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed four (4) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 2-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

b. *Gas Turbine/HRSG System Cold Startup:* For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

c. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period. "Warm startup of the steam turbine system" is defined as startup of the 2-on-1 combined cycle system following a shutdown of the steam turbine lasting more than 8 hours and less than 48 hours.

d. *Shutdown Combined Cycle Operation:* For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period.

e. *Fuel Switching:* For fuel switching, excess emissions shall not exceed two (2) hours in any 24-hour period.

As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions for each CT only for specifically defined periods of startup, shutdown, fuel switching and documented malfunction of the gas turbines or the SCR systems. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

2.2.2 Combined Cycle Operation

The Project will be configured as a 2-on-1 combined cycle unit for base load service. The CTs will use combustion technology when firing product gas and natural gas (during startup) to minimize NO_X formation. An SCR system will be installed in each HRSG to further reduce NO_X emissions. Product gas will be the primary fuel and natural gas will be limited to the equivalent of 750 hours per year (hr/yr) to address startups.

For the Solar T-130 CTs, the maximum heat input is 147 MMBtu/hr (LHV) for each CT when firing product gas or natural gas (100 percent capacity, 59°F). The corresponding fuel usage is about 333,333 cubic feet per hour (cf/hr) of product gas (based on a heating value of 435 Btu/cf- LHV) or about 148,000 cf/hr of natural gas for each CT (based on a heating value of 980 Btu/cf- LHV). Maximum potential annual fuel usage at 59°F turbine inlet temperature would be about 5.8 billion cubic feet per year (cf/yr) of product gas for the 2-on-1 combined cycle unit using the Solar T-130 Class CTs. Assuming no more than 750 hr/yr of natural gas-firing for startups, annual natural gas usage would be approximately 225 million cf/yr. This represents approximately 6 startups per year and less than 10 percent of total operating hours. Of course, for every hour of natural gas firing, there will be one hour less of product gas firing reflected in the above figures.

Each of the two duct burners, one for each HRSG, will have a maximum product gas firing rate of 28 MMBtu/hr. The hourly fuel usage for each duct burner is about 64,400 cf/hr (based on a product gas heating value of 435 Btu/cf—LHV). The maximum potential annual product gas usage for the duct burners is calculated to be about 1.1 billion cf/yr (based on both DBs operating for 8,760 hr/yr). Product gas will be the only fuel fired in the duct burners. Plant performance for each of the CTs under consideration for the Project was developed for product gas-firing at 100 percent load and turbine inlet temperatures of 25°F, 59°F and 95°F.

3.0 PROPOSED SOURCE EMISSIONS AND CONTROLS

Estimated maximum hourly emissions, annual emissions and proposed control technology information representative of each emission unit during normal operation are provided in the following sections. Table 3-1 provides a summary of total project emissions, including mercury and other hazardous air pollutants. Individual process units were described in detail in Section 2.0 of this report. The following is a summary listing of the process units considered in this emissions evaluation:

- Power Block, consisting of CT/DB Trains 1A and 1B;
- Gasifier Combustor
- Material Handling (i.e., feedstock conveying and storage);
- Feedstock Dryer;
- Auxiliary Boiler;
- Flare Systems; and
- Cooling Towers

The above-listed emission units can be located on Figure 2-3 (Overall Process Schematic) and referenced to ID Nos. 1 through 7.

3.1 Power Block

The CT/HRSG case operating at base-load is presented in Table 3-2 for product gas firing in combined cycle mode. These units are identified as ID Nos. 1A and 1B on Figure 2-3. Plant performance for each of the CTs and DBs was developed for product gas-firing at 100 percent load and turbine inlet temperatures of 25°F, 59°F and 95°F. The maximum short-term emission rates in pounds per hour (lb/hr) generally occur at base load operation at 25°F, where the CT has the greatest output and greatest fuel consumption. The CTs will be equipped to operate concurrent with DB firing in the HRSG. Therefore, this analysis assumes that the maximum short-term emission rate occurs at base load, 25°F operation, with DB firing. On an annual basis, this analysis assumes that the CTs will each operate at an annual average temperature of 59°F, up to 8,760 hours per year. In addition, each DB is assumed to fire up to 8,760 hours per year.

Emissions of CO and VOCs will be minimized through good combustion practices. SO_2 emissions will be minimized through utilization of natural gas during startups and the gas clean-up system on the product gas.

When firing product gas , NO_X emissions from the turbines and duct burners will be controlled using good combustion techniques and SCR systems, to approximately 27 parts per million or less by volume dry (ppmvd), corrected to 15 percent O_2. The SCR reactors will be located in each HRSG to provide the proper operating temperature range for the required reaction between ammonia and NO_X to achieve additional NO_X reductions. The ammonia handling system will include diluent air blowers (each sized for 100-percent capacity), ammonia flow control and measurement devices, an ammonia/air mixing chamber, distribution header(s), and an ammonia injection grid (AIG). Overall control of the system will be by a distributed control system (DCS).

Emission factors for hazardous air pollutants (HAPs) were evaluated based on AP-42, the U.S. Environmental Protection Agency (EPA) Combustion Turbine Emissions Database, and the combustion turbine Maximum Achievable Control Technology (MACT) standards. The HAP emissions are based on the April 2000 revision of EPA's AP-42 emission factors for stationary combustion turbines. CT/DB HAP emissions are presented in Table 3-3. It is assumed that the product gas composition, relative to the composition of natural gas, allows for a similar application of these factors.

3.2 Gasifier/Combustor System

Table 3-4 provides a summary of emission estimates from the gasifier/combustor system. This emission point is identified as ID No. 2 on Figure 2-3. A schematic diagram of the gasification process was previously provided in Figure 2-5. The gasifier, combustor, cyclones and baghouse are the primary equipment components of the gasification process. In addition, there are small natural gas-fired start-up burners associated with the gasifier and combustor. These small burners are more fully described in the section addressing startup emissions.

Flue gas from the combustor flows through an additional cyclone, heat recovery exchangers and a baghouse before exhausting to the atmosphere. Product gas from the gasifier is directed to the gas clean-up system for removal of impurities prior to utilization in the two Solar Model T-130 combustion turbine generators (CTs).

The emissions produced by the combustor have been estimated based on the use of the same emission factors as anthracite coal burned in a conventional fluidized bed combustor boiler.[1] Anthracite was chosen because it has a higher carbon content and lower volatile content than lower ranked coals. Since nearly all the volatile components of the biomass are removed in the gasification process and the resultant char is nearly all carbon and ash, anthracite is a reasonable estimate without specific test data.

While the conventional AP-42 factor is considered conservative, char combustion NO_x emissions will be inherently lower because combustion in the combustor will take place at reduced excess air levels as compared to a traditional fluidized bed boiler, which can run 10 to 20 percent excess air by comparison. Based on information in a 1989 Battelle Report, excess air in the combustor was approximately 0.5 percent to 2.5 percent. According to AP-42 Chapter 1, Section 1.1 for Bituminous and Subbituminous Coal Combustion, low excess air combustion results in a 10 percent to 20 percent reduction in NO_x emissions. The upper range of the control efficiency was applied to the char combustion emission factor based on the extremely low levels of excess air in the combustor as presented in the Battelle Report. Note that the anthracite coal combustion section did not discuss the impact of low excess air on NO_x emissions. However, it is assumed that the reductions discussed in relation to bituminous and subbituminous would also apply to char combustion.

SO_x emissions are a combination of sulfur dioxide, SO_2, with traces of SO_3, sulfur trioxide. Typically, less than 0.1 percent sulfur would be expected in the feedstock. Sulfur, which goes into the product gas or the combustor flue gas, is considered to be primarily derived from the decomposition of organic sulfur sources. In the product gas, the primary sulfur-containing constituent is H_2S, while in the combustor flue gas it will be SO_2. Organic sulfur in the amino acids in the biomass typically runs at a concentration of about 10 percent that of the nitrogen content of the amino acids. From vendor analyses received by BG&E, sulfur concentrations average around 0.01 to 0.04 percent. For instance, the emission estimate based on a sulfur content of 0.04 percent sulfur would have organic sulfur emissions at 10 percent of this, or 0.004 percent.

Filterable PM is that material which will ultimately exit the baghouse. Condensable PM consists of fine droplets, typically sulfates and nitrates. Condensables are not significant in the analysis, as the constituents that would comprise condensable PM are controlled in the reactions between the gasifier

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[1] AP-42 Chapter 1, Section 1.2 for Anthracite Coal Combustion.

and the combustor, as well as the downstream gas cleanup system. Emissions from the gasifier combustor system are provided in Table 3-4.

3.3 Material Handling System Description

Emission estimates from the material handling system are presented in Table 3-5. This component of the process operation is depicted by ID No. 7 on Figure 2-3. In addition, a more detailed process schematic of the handling system was presented in Figure 2-4. Finally, the ash and olivine transfer and storage systems are depicted in Figure 2-5. Woody biomass feedstock preparation will occur at a remote site that will be owned and operated by others. A description of the material handling system was provided earlier. Emissions are primarily associated with the transport and storage of the biomass feedstock on the site. The feedstock received will have a moisture content of 30 to 40 percent, minimizing the potential for fugitive dust. In addition, all conveying systems will be enclosed and transfer points equipped with bin vent and/or baghouse controls. The feedstock storage building is proposed to be under roof and mostly enclosed, except for an open area that allows for feedstock ventilation.

3.4 Feedstock Dryer

The dryer is depicted as ID No. 3 on Figure 2-3. Emission estimates for the feedstock dryer are presented in Table 3-6. The dryer will use waste heat (i.e., no combustion involved) at a temperature of ~ 175 degrees F and a flow rate of ~110,000 scfm. It is assumed that the feedstock throughput will be approximately 1,000 wet tons per day of wood (based on 30 percent moisture), which would produce 730 tons per day of feed to the gasifier (dry basis).

3.5 Auxiliary Boiler

Table 3-7 presents estimated performance and emissions information for the future auxiliary boiler. This emission unit is designated as ID No. 4 on Figure 2-3. Provisions for an auxiliary boiler are included in the Project design to assist in gasifier and combined cycle startup, if required in the future. Once sufficient quality and quantity of steam is available from the HRSG, steam from the auxiliary boiler is not required. The future steam boiler will be a Nebraska Boiler or equivalent with steam capacity of 50,000 lb/hr and a heat input rating of up to 62 MMBtu/hr. It was conservatively assumed that the annual operation of the auxiliary boiler would be 500 hr/yr or less. The proposed controls for the auxiliary boiler include good combustion practices to limit emissions of NOx, CO and VOC. Natural gas is the cleanest fossil fuel and will minimize the emissions of PM and SO_2 to low emission levels. The auxiliary boiler will also limit NOx emissions using low-NO_X burners. The emission limits and control technology proposed will meet the Florida-specific small boiler BACT requirements (62-296.406, F.A.C.), as well as NSPS Subpart Dc.

3.6 Flare System

A safety vent and flare system, located downstream of the heat recovery section of the gasification plant, provides a means for emergency venting of the product gas to a flare. The two proposed flares are depicted as ID Nos. 5A and 5B on Figure 2-3. There are three operating conditions under which the flare system may potentially be needed: startup, planned shutdown and emergency shutdown (i.e., in the event of a gasifier trip). The flare system is provided with a pilot fuel to continuously operate the flare pilots. The large combustion chamber in each of the two flares provides a stable environment to burn the gas produced during process upsets.

The flare type would likely be of an open design with a height close to 30 feet. Estimated emissions are presented in Table 3-8. A typical composition of the product gas to be flared was previously presented in Table 2-1. This would occur in the event of a process trip or malfunction.

3.7 Cooling Towers

Cooling towers will be required for the steam turbine and for the cooling of compressor gases. The wet surface air condenser (~ 7,050 gpm) is the condenser for the steam turbine provided in the project and employs a different technology than a traditional surface heat exchanger (condenser) and cooling tower. In a traditional cooling tower, such as the one to be used for cooling of compressor gases, the cooling water is sprayed onto surfaces and cooled by evaporation of air drawn across the surfaces. This water (~ 3,800 gpm) is then used in a heat exchanger to cool or condense the fluid. Particulate emissions from each of the two cooling towers will be controlled by specifying drift eliminators that will result in a low drift rate (0.002 and 0.005 percent drift, respectively). The mechanics of the two different types of equipment account for the difference in their drift rates. In addition, the total dissolved solids (TDS) content of the cooling water is very low. Estimated emissions are presented in Table 3-9.

3.8 Site Layout, Structures, and Stack Sampling Facilities

A plot plan of the proposed project was previously presented in Figure 2-2 (Project Site Layout). The approximate dimensions of the buildings and structures are also presented in this figure. Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6), F.A.C.

4.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal, state, and local air regulatory requirements and their applicability to the Project. These requirements must be satisfied before the proposed facility can begin construction and/or operation.

The FDEP regulations require any new source to obtain an air permit prior to construction. New sources must meet the appropriate requirements and obtain the required permits and approvals for air pollution sources, including Prevention of Significant Deterioration (PSD) (if major), applicable New Source Performance Standards (NSPS), applicable National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C., and 40 CFR Parts 60, 61, and 63.

FDEP has nonattainment provisions (Rule 62-212.500, F.A.C.) that apply to all major new facilities located in a nonattainment area. In addition, for major facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Project is located in Leon County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment new source requirements are not applicable. There are currently no local air quality regulations more stringent than those at the state level.

4.1 New Source Review (NSR) Requirements

Under federal and Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed, and a pre-construction permit issued. As Florida's EPA approved State Implementation Plan (SIP) includes PSD regulations, the Florida Department of Environmental Protection (FDEP) has PSD approval authority.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. The Project is not classified as any of the listed 28 source categories; therefore, the threshold for a major facility classification is 250 TPY of any pollutant. The project emissions summary, presented in Table 3-1, indicates that all pollutants are below the applicable threshold.

4.2 New Source Performance Standards (NSPS)

The New Source Performance Standards (NSPS) are national emission standards, 40 CFR 60, that apply to specific categories of new sources. As stated in the 1977 Clean Air Act Amendments, these standards “shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated.”

4.2.1 NSPS 40 CFR 60 Subpart Da (Electric Utility Steam Generating Units)

This rule applies to combined cycle combustion turbines associated with an integrated gasification combined cycle (IGCC) system if: (1) the turbine is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and (2) the turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis. "Solid-derived fuel” means “any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquefied coal, synthetic gas, gasified coal, gasified petroleum coke, *gasified biomass*, and gasified tire derived fuel." The heat input to each of BG&E’s turbines is a nominal 145 MMBtu/hour, which is less than the threshold level of 250 MMBtu/hour. Therefore, this rule does not apply to the combustion turbines. This rule could also apply to the duct burners if the turbines were subject to Subpart Da or if the duct burners themselves had a heat input of more than 250 MMBtu/hour. Because the turbines are not subject to Subpart Da and the maximum heat input rate for each of the duct burners is only 28 MMBtu/hr,this NSPS therefore does not apply to the proposed turbines or the duct burners.

4.2.2 NSPS 40 CFR 60 Subpart Dc (Standards for Small Industrial-Commercial-Institutional Steam Generating Units)

The proposed auxiliary boiler will be an affected facility to which this subpart applies, as it will be constructed after June 9, 1989 and will have a maximum design heat input capacity of 100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 10 MMBtu/hr. The proposed use of natural gas and limited operating hours (i.e., 500 hours per year, or less than a 10 percent capacity factor) will easily allow compliance with the applicable standards.

4.2.3 NSPS for Stationary Combustion Turbines and Duct Burners (40 CFR 60, Subpart KKKK)

EPA promulgated new NSPS for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK) that commence construction after February 18, 2005. This new final rule was effective on July 6, 2006. The stationary combustion turbines subject to Subpart KKKK, 40 CFR 60 (i.e., 10 MMBtu/hr or greater), are exempt from the requirements of 40 CFR 60, Subpart GG for combustion turbines. Heat recovery steam generators and duct burners subject to Subpart KKKK are exempt from the requirements of 40 CFR 60, Subparts Da, Db and Dc for duct burners. The Subpart KKKK emission limits apply not only the combustion turbines but also to emissions from any associated duct burners and heat recovery steam generating units.

NO_X emissions for these proposed units (i.e., firing fuels other than natural gas, with a heat input > 50 MMBtu/hr and < 850 MMBtu/hr) are limited by Subpart KKKK to 74 ppmvd corrected to 15-percent O_2 (or 3.6 lb/MW-hr). SO_2 emissions are limited to 0.90 lb/MW-hr or 0.60 lb/SO_2/MMBtu heat input while firing product gas and a sulfur content of no greater than 20 grains of sulfur per 100 standard cubic feet for natural gas-firing. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR Subpart A. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

- (a)(1) Notification of the date of construction - 30 days after such date.
- (a)(3) Notification of actual date of initial start-up - within 15 days after such date.
- (a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

(c) Excess emissions reports – semi-annually by the 30th day following six-month period (required even if no excess emissions occur).

(d) Maintain file of all measurements for two years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

4.2.4 NSPS Subpart Eb (Municipal Waste Combustion Units; Commercial)

Subpart Eb applies to new municipal waste combustor units with a combustion capacity of greater than 250 tons per day of municipal solid waste. Qualifying small power production facilities, as defined in section 3(17)(c) of the Federal Power Act, that burn homogenous waste (excluding refuse-derived fuel) for the production of electricity are not subject to Subpart Eb. The owner or operator of such a facility must notify EPA of the exemption and provide supporting documentation. The Project is a qualifying small power production facility and will use only homogenous woody biomass as a feedstock for the gasifier, with a small percentage of it constituting “municipal solid waste” (e.g., yard trimmings). It is estimated that no more than 30 TPD, quarterly average, would be utilized as feedstock. If appropriate, documentation to support this exemption can be provided to EPA and the Department.

4.2.5 NSPS 40 CFR 60 Subpart CCCC (Industrial Solid Waste Incineration Units)

This rule applies to new commercial and industrial solid waste incineration (CISWI) units, although the definition of “commercial and industrial solid waste incineration units” has been vacated and remanded to EPA. (*Natural Resources Defense Council v. EPA*, 489 F.3d 1250 (D.C. Cir. June 2007). Without this critical definition, applicability of this standard is indeterminable. In addition, “qualifying small power production facilities” and “chemical recovery units” (conversion of hydrocarbon solids to syngas) are both exempt from this rule. Subpart CCCC is therefore not applicable to the Project’s gasifier, at least at this time.

4.2.6 NSPS 40 CFR 60 Subpart RRR (VOC Emissions from SOCMI Reactor Processes)

According to 60.700(a), this subpart applies to a process unit that produces any of the listed chemicals as a product, co-product, byproduct or intermediate. Product is defined as any compound or chemical listed in 60.707 that is produced for sale as a final product as a chemical or for use in the production of other chemicals or compounds. It also states that co-product, byproducts and intermediates are considered products. Since the Project is not using the product gas to sell as a final product or for use in producing other chemicals or compounds, this regulation does not apply.

4.3 National Emission Standards for Hazardous Air Pollutants (MACT Standards)

BG&E's Tallahassee Project is not major for HAPs. The standards under 40 CFR Part 63 are, therefore, not applicable.

4.4 Florida Rules

Florida has adopted the NSR program requirements, NSPS and NESHAPs by reference. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in the previous sections.

4.4.1 Rule 62-296.401, F.A.C., Incinerator Rule

BG&E has determined that Florida's rule applicable to "incinerators" would not apply to this Project. The Department's rules broadly define "incinerator" as a "combustion apparatus designed for the ignition and burning of solid, semi-solid, liquid or gaseous combustible wastes." The Tallahassee unit is expected to use some waste forms of biomass as a feedstock for the gasifier system (e.g., agricultural waste, clean construction and demolition debris, urban yard trimmings, etc.). The gasifier, however, will use a pyrolysis system (absence of air) to convert biomass to product gas, which is not "combustion" or "ignition and burning." Residual char from the pyrolysis system will be combusted in the chamber associated with the gasifier, but the "char" is not a waste. The product gas produced from the gasifier, also not a waste, will subsequently be combusted in the combustion turbines and duct burners. Therefore, no waste is incinerated through a combustion process, and this rule should not apply.

4.4.2 Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment

Carbonaceous fuel is defined in the Department’s rules as solid materials composed primarily of vegetative matter such as tree bark, wood waste, or bagasse. The vegetative matter (biomass) to be used as the feedstock in the primary chamber of the gasifier is not “burned” or combusted. The biomass will be heated with olivine in the absence of oxygen without combustion. The resulting “char" will then be combusted in the second chamber of the gasifier, although the material is not a fuel or “vegetative” matter at that point. The primary "fuel burning" is to occur in the combustion turbines and duct burners, however, the fuel is product gas and not a solid. This rule, therefore, does not appear applicable to the Project.

4.4.3 Rule 62-296.416, F.A.C., Waste-to-Energy

The Department’s rules define the term “waste-to-energy facility” as a facility that uses controlled combustion to thermally break down solid, liquid, or gaseous combustible solid waste to an ash residue that contains little or no combustible material and that produces electricity, steam, or other energy as a result. The term does not include facilities that primarily burn fuels other than solid waste, even if the facilities also burn some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel [Rule 62-210.200(331), F.A.C.]. Because wood waste is being used as the primary feedstock and product gas is being used as the primary fuel, this rule would not apply to the Project.

4.5 Other Clean Air Act Requirements

4.5.1 The Acid Rain Program

The 1990 Clean Air Act Amendments established the Acid Rain Program to reduce the release of acidic deposition precursors, SO_2 and NO_X. EPA’s final regulations were promulgated on January 11, 1993, and included permit provisions (Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

This Acid Rain Program generally applies to all existing and new utility units. "Utility unit" is defined to mean "a unit owned and operated by a utility …. that serves a generator in any State that produces electricity for sale." "Utility" is defined to mean "any person that sells electricity." Under these definitions, BG&E would be considered a "utility" and the proposed combined cycle turbine units would be considered "utility units." There are exceptions to the Acid Rain Program for certain types of units (e.g., small units serving generators with nameplate capacities of less than 25 MWs, pre-1991 small simple cycle combustion turbines, cogenerating facilities, qualifying facilities and independent power producers with contracts in effect as of 1990, solid waste incineration units, etc.), none of which appear applicable to the Tallahassee project. The Acid Rain Program therefore appears applicable to the Project. Accordingly, applications for an Acid Rain permit and a Certificate of Representation are also included in this air permit application package.

4.5.2 Regional Haze

The Department's Best Available Retrofit Technology (BART) rule applies to facilities in existence on August 7, 1977, and that have the potential to emit 250 tons per year or more of any air pollutant (Rule 62-296.340, F.A.C.). The Project does not meet these criteria and therefore the BART rule does not apply. Similarly, the Department's Reasonable Further Progress rule applies to units in existence as of August 30, 1999. Therefore, this rule is also not applicable to the Project (Rule 62-296.341, F.A.C.).

4.5.3 Clean Air Interstate Rule (CAIR)

Generally, the CAIR program applies to stationary boilers and combustion turbines that fire any amount of fossil fuel at any time and serve a generator with a nameplate capacity of more than 25 MWs, producing electricity for sale. As the nameplate capacities of the individual generators proposed for the Project are less than 25 MW, CAIR is not applicable to this Project. Specifically, each of the two combustion turbines are rated at a nominal 14.8 MW and the steam turbine is rated at a nominal 20.7 MW.

4.5.4 Greenhouse Gas (GHG) Rulemaking

The use of biomass is generally recognized as "carbon neutral."[2] The U.S. EPA found that because biomass fuels are of biogenic origin, it is assumed that the carbon released during the consumption of biomass is recycled as forests and crops regenerate, causing no net addition of CO_2 to the atmosphere.[3] In addition, the Intergovernmental Panel on Climate Change (IPCC) recently found that bioenergy and the use of dedicated energy crops were key climate change mitigation technologies that should be pursued and "could contribute substantially to the share of renewable energy in the mitigation portfolio".[4]

When biomass is used as a feedstock or a fuel, the carbon involved is on a relatively "short-cycle"—i.e., the carbon dioxide (CO_2) is produced from the oxidation of current or recently-living biomass. Since the CO_2 was recently in circulation in the atmosphere, there is no net addition of new CO_2 when it is returned to the atmosphere. For example, when the grass in a person's front yard grows, it removes some CO_2 from the air during photosynthesis and growth. When the yard is mowed, the cut grass decomposes, returning the CO_2 to the atmosphere within days. For other types of biomass, the cycle may take months or even a few years to complete, but the timeframe is still relatively short, and the carbon dioxide released when that biomass is burned or decomposed is not a "new" net addition to the total. The CO_2 balance would be zero. Even when the entire "life cycle" is considered, the use of biomass is still considered carbon neutral.

A complete "life cycle" assessment, which is appropriate for use in considering project's CO_2 emissions, is where the environmental benefits and impacts are quantified in a cradle-to-grave manner to cover resource consumption and all processes necessary for a power generation system.[5] A life cycle assessment for a biomass facility would include energy and resources used for crop cultivation, preparation, and transportation; construction and operation of the power generation system;

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[2] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories,* Vol. 3, p. 6.28 (1997); The Climate Registry, *General Reporting Protocol for the Voluntary Reporting Program, Draft for Public Comment* (October 29, 2007), p. 22 (separate reporting for carbon dioxide emissions from biogenic sources); California Environmental Protection Agency, Air Resources Board, *Staff Report: Initial Statement of Reasons for Rulemaking, Proposed Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32)* (October 19, 2007), pp. 5, 12 (carbon dioxide emissions from biomass-derived fuels are to be separately identified during reporting; biomass emissions are generally considered "carbon neutral").

[3] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006* (February 22, 2008), Public Review Draft, p. 3-1.

[4] Intergovernmental Panel on Climate Change, *Contribution of Working Group III to the Fourth Assessment Report* (2007), pp. 10, 16.

emissions; and wastes. Such analyses have indicated that biomass-based power generation systems have neutral or very minimal CO_2 emissions, in part because, as mentioned above, trees and plants absorb CO_2 as they grow and also because CO_2 can accumulate in the soil.[6] When waste biomass is used, the greenhouse gas emissions are further reduced because of the avoided methane generation associated with biomass decomposition that would have occurred had the waste biomass not been used by the power generation system.[7] This results in a net reduction of greenhouse gas emissions.

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[5] Governor's Action Team on Energy and Climate Change, *Phase 1 Report: Florida's Energy and Climate Change Action Plan Pursuant to Executive Order 07-127* (November 1, 2007), p. 24 (life cycle assessments are appropriate).

[6] National Renewable Energy Laboratory, *Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas,* Margaret K. Mann and Pamela L. Spath (November 2002); National Renewable Energy Laboratory, *Life Cycle Assessment of Biomass Gasification Combined-Cycle System,* Margaret K. Mann and Pamela L. Spath (December 1997); Biomass and Energy 25, *Life Cycle Assessment of a Willow Bioenergy Cropping System,* Martin C. Heller, Gregory A. Keoleian, Timothy A. Volk (2003), pp. 147-165.

[7] National Renewable Energy Laboratory, *Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas,* Margaret K. Mann and Pamela L. Spath (November 2002).

TABLES

FIGURES

APPLICATION FORMS

APPENDIX A

LIFE CYCLE ASSESSMENT