TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Biomass Gas and Electric of Tallahassee, LLC
Tallahassee Renewable Energy Center

42-Megawatt (net) Biomass Integrated Gasification Combined Cycle

Leon County

DEP File No. 0730109-001-AC

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Special Projects Section

October 24, 2008

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Biomass Gas and Electric of Tallahassee, LLC (BG&E)
3500 Parkway Lane, Suite 440
Atlanta, Georgia 30092

***Authorized Representative*:** Mr. Glenn Farris, President and CEO

1.2. Processing Schedule

April 2, 2008:	Received air construction permit application from BG&E for the Tallahassee Renewable Energy Center (TREC).
May 2, 2008:	Sent request for additional information (RAI) to BG&E.
July 28, 2008:	Received response to RAI from BG&E.
October 24, 2008:	Intent to Issue PSD Permit distributed.

1.3. Facility Location

The proposed Tallahassee Renewable Energy Center (TREC) will be located in Tallahassee, Leon County, Florida. The site is located approximately 33 kilometers to the North of the St. Marks National Wildlife Refuge; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area. The approximate UTM coordinates for this site are Zone 16; 757.5 km East and 3,369.6 km North. The location of the proposed TREC is shown in Figure 1.

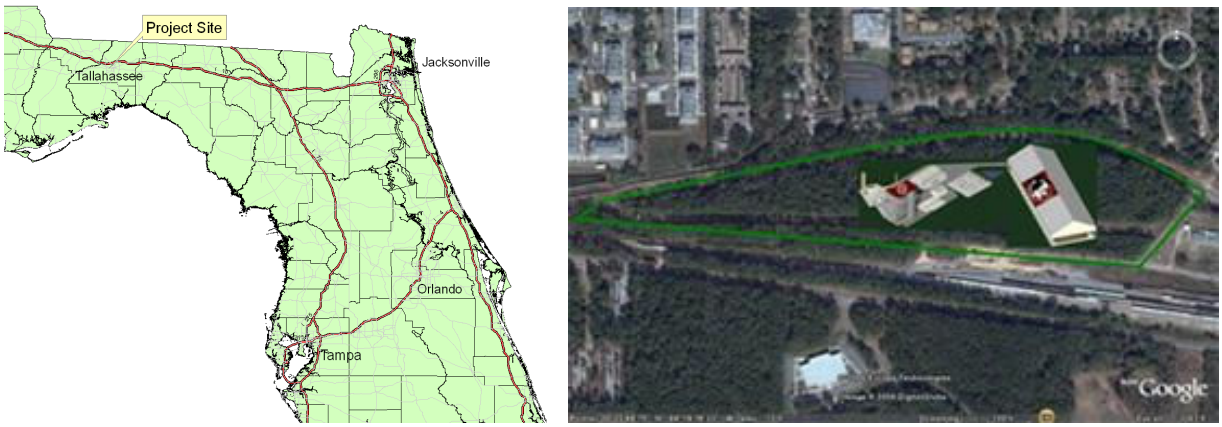

Figure 1. Project Location in Tallahassee and Rendition of Future TREC Project Site.

The location is a 21.2 acre parcel that lies north of Roberts Avenue. The property is bounded on the north, west and south sides by CSX railroad tracks and on the east side by an extension of Lipona Road. The title is held by the State of Florida Board of Trustees of the Internal Improvement Trust Fund. The premises are managed by Florida State University who subleased it to BG&E.

The following figure includes a map from the Leon County Property Appraiser's Office showing the land uses adjacent to the proposed site. Photographs taken within and near the boundaries of the site are included. The BG&E site layout is included.

Innovation Park is a university-related research and development park located south of Roberts Avenue. There is a combination of residential and commercial areas to the north, east and west of the site. There is a City of Tallahassee electrical substation immediately to the east of the site.

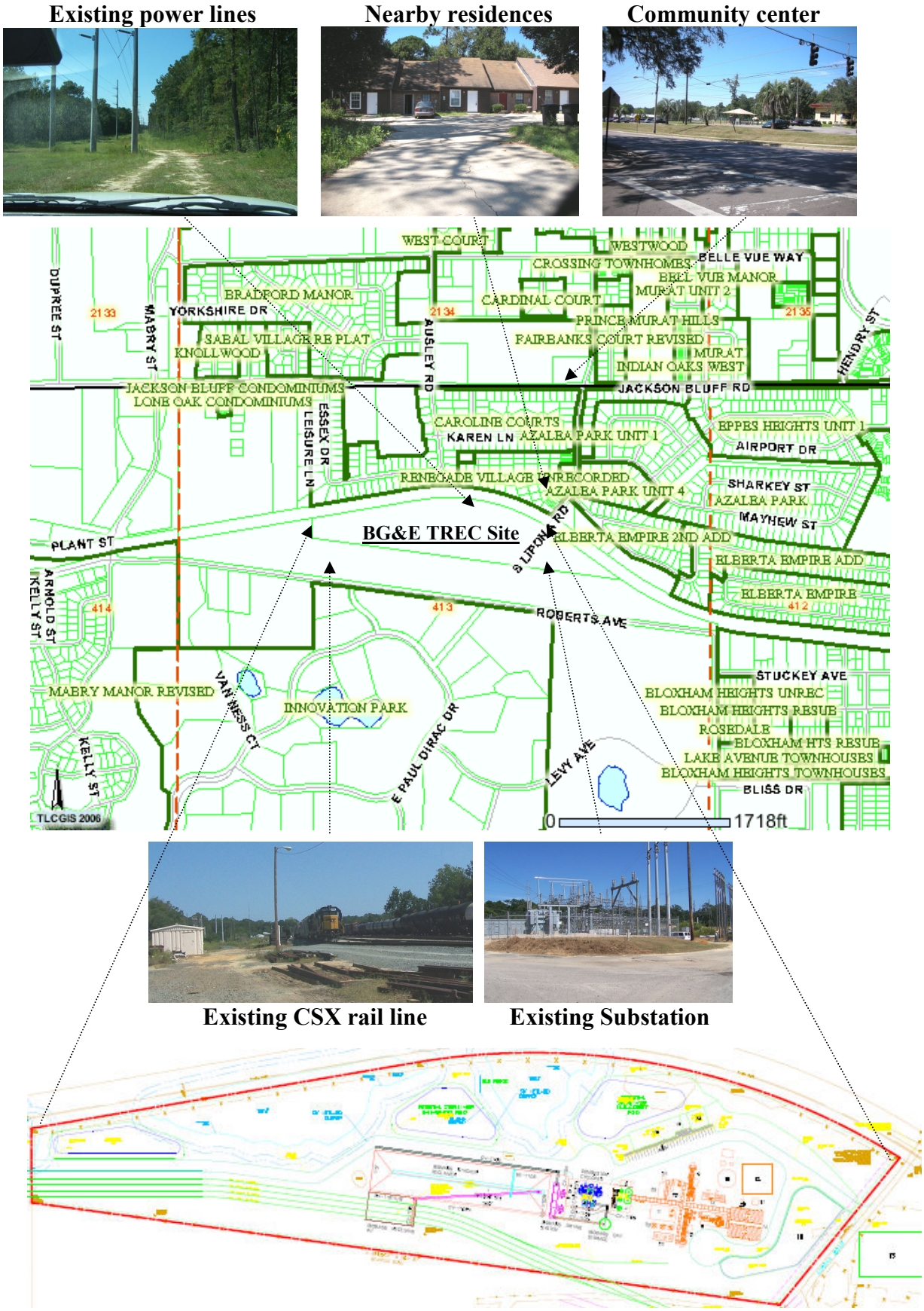

Figure 2. BG&E site layout of TREC. Insert into Tallahassee Leon County map above.

1.4. Regulatory Categories

Section 111, Clean Air Act, Standards of Performance for New Stationary Sources

The proposed project is subject to:

- 40 CFR 60, Subpart A—General Provisions
- 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.
- 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines.

Section 112, Clean Air Act, Hazardous Air Pollutants (HAP)

The proposed facility is not a major source of HAP.

Title IV, Clean Air Act, Acid Rain Provisions

The facility will be subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits

The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant will exceed 100 tons per year (TPY). Key regulated pollutants include carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

Part C, Clean Air Act, Prevention of Significant Deterioration (PSD)

The facility is not classified as a "Major Stationary Source" because it will not have the potential to emit (PTE) 250 TPY or more of a PSD pollutant and is not one of the facility categories with the PSD applicability threshold of 100 TPY as described in Section 62-210.200, Florida Administrative Code (F.A.C.).

Siting

The facility is not subject to certification pursuant to the power plant siting provisions of Chapter 62-17, F.A.C. because it will produce less than 75 megawatts (MW) of power.

Section 403.061(18). The department has the power and the duty to encourage and conduct studies, investigations, and research relating to pollution and its causes, effects, prevention, abatement and control.

Besides supplying a portion of the renewable energy need to a municipal utility, the project is the first relatively large installation of a biomass integrated gasification and combined cycle (BIGCC) unit in this part of the country.

2. PROPOSED PROJECT SUMMARY

2.1. Project Description

The applicant proposes to construct a nominal 42 MW (net) BIGCC unit and auxiliary equipment. The BIGCC unit will consist of: a biomass gasification system that yields biomass product gas (BPG); two BPG-fueled Solar T-130 combustion turbine-electrical generators (CT); two supplementary-fired heat recovery steam generators (HRSG) equipped with duct burners (DB); a steam turbine-electrical generator (STG); CT/HRSG and char combustor exhaust stacks; and two flares.

Additional equipment will be included to accomplish:

- Biomass storage, handling, drying and feeding;
- BPG cooling and heat recovery;

- Char separation and combustion (with tars);
- BPG particulate and tar removal;
- Ash and tar handling;
- BPG scrubbing;
- BPG compression;
- Ammonia injection in the CT; and,
- Cooling of steam turbine condensate and compressor gas.

2.2. Additional Project Features

Fuel

Municipal Solid Waste is prohibited as a fuel at this facility. The TREC will generate electricity from BPG, char and tar derived on-site from woody biomass. Natural gas will be used primarily as a startup fuel.

Generating Capacity

The BIGCC will have a nominal electrical generating capacity of 42 MW (net), 51 MW (gross).

Air Pollution Controls – Char/Tar Combustor

- SO_2 will be limited by use of woody biomass that is low in sulfur compared with typical fossil fuels. Gasified sulfur gases will tend to follow the BPG stream and not the char.
- PM/PM_{10} will be reduced by combustion in an oxidizing atmosphere followed by cyclones and filtration in a fabric filter (FF) baghouse.
- Carbon monoxide (CO) and volatile organic compounds (VOC) emissions are limited by sufficiently high temperature combustion.
- NO_X formation is limited by combustion in a circulating fluidized bed (CFB) of olivine (sand) at temperatures less than those characteristic of thermal NO_X formation.
- Dioxin and furan (D/F) formation potential is limited by relatively low chloride in woody biomass and sufficient residence time at destructive temperatures.
- Mercury (Hg) is inherently low in the woody biomass compared with typical fossil fuels or wastes.
- It is estimated that the char will contain approximately 14,500 British thermal units (Btu) per pound (lb). The heat input from the char combustor to the system will be approximately 124 million Btu per hour (mmBtu/hr) or about 25 percent of the total.

Air Pollution Controls – BPG Combustion in CT and DB

- SO_2 is limited by use of woody biomass that is low in sulfur compared with typical fossil fuels and also by removal of hydrogen sulfide (H_2S) through caustic scrubbing as described below.
- PM/PM_{10} will be removed from the BPG by the gasifier cyclones, coarse and fine solids removal systems and high temperature combustion in the CT and DB.
- NO_X formation is limited by: minimal atmospheric nitrogen (N_2) available for thermal NO_X formation; removal of nitrogen compounds such as ammonia (NH_3) in the water scrubber prior to combustion; and by selective catalytic reduction (SCR) in the HRSG following combustion.
- HCl is also removed in the water scrubber.

- CO and VOC will be controlled by high temperature combustion.
- D/F is limited by: relatively low chloride in woody biomass; removal of tar from BPG; scrubbing of gaseous chlorides prior to combustion in the CT; and further oxidation by SCR in the HRSG after combustion in the CT and DB.
- Each HRSG will have a combined cycle stack with a nominal diameter of 78 inches. The following table summarizes the exhaust characteristics of each of the two CT/HRSG sets, inclusive of the DB and while firing BPG:

Table 1. Exhaust Characteristics of each HRSG (CT/DB) at 100% Load and 59 °F.

BPG Heat Input Rate to CT, DB Lower Heating Value (LHV)		Compressor Inlet Temp., °F	Stack Exhaust Temp., °F	Stack Exhaust Flow lb per hour (lb/hr)
CT	147 mmBtu/hr	59 °F		
DB	42 mmBtu/hr			
Total	189 mmBtu/hr		364 °F	410,210

3. PROCESS DESCRIPTION

3.1. Principle

Integrated gasification and combined cycle (IGCC) involves the incomplete combustion of fuel or residues in a reducing atmosphere and then combustion of the resultant product gas in an oxidizing atmosphere with associated heat recovery, chemical production, steam generation, and electrical power production.

The term "integrated" relates to varying degrees of interchange of air, steam, condensate, feed water, fuel, electricity, etc. between the key gasification step, the combustor and the combined cycle (CT/HRSG/STG). "Integration means recovery of the waste energy available, improvement of the efficiency and, where possible, reduction of the investment cost."[1] BIGCC as described for this project includes and integrates the char combustion step.

3.2. Fuel slate and sources

The feedstock will consist of woody biomass that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. BG&E has identified the following possible, available feedstock types for the TREC, including: sander dust; saw dust; Georgia Pacific (GP) fuel; hogged fuel; processed butt cuts, knots and shives and a vegetative crop.

GP fuel is the reject material from the round wood debarking system at the GP oriented strand board mill in Hosford, Florida. Hogged fuel is material that comprises land clearing debris that has either been pre-processed, run through a tub grinder, or a horizontal mill at a specific private forest clearing site. Knots and shives are the residues from the specialty pulping operation at Florida Buckeye in Perry.

Woody biomass consists of cellulose, hemicellulose, lignin and minerals. BG&E submitted fuel analyses for biomass of the kind they intend to use at the TREC. The key values are given in Table 2. A similar analysis for a typical Eastern Kentucky (E. KY) bituminous coal (vitrinite) is presented for comparison.

In general, the key differences between the biomass and E. KY coal are:

- Biomass contains more moisture, volatile matter and oxygen (O_2);

- Biomass contains much less carbon and has much less calorific value even on a dry basis; and
- Biomass contains less sulfur, fluorine, chlorine, N_2 and Hg.

Table 2. Analyses of candidate biomass feedstock compared with typical bituminous coal.

Parameter	Sander Dust	Saw Dust	GP Fuel	Hogged Fuel	Knots Shives	Butt Cuts	Crop Fuels	E. KY Coal
Proximate Analysis (dry)								
Moisture (%)	4.89	59.68	36.14	34.54	61.59	31.52	23.35	2.38
Ash (%)	0.79	3.12	1.80	1.67	8.48	0.48	3.80	12.27
Calorific Value (Btu/lb)	8,395	8,458	9,061	8,254	7,655	8,336	8,070	12,900
Volatile Matter (%)	78.79	78.15	75.15	79.37	73.71	83.25	75.75	35.79
Fixed Carbon (%)	20.42	18.73	23.05	18.96	17.81	16.27	20.34	51.94
Ultimate Analysis (dry)								
Sulfur (%)	0.08	0.02	0.06	0.03	0.36	0.01	0.11	1.52
Carbon (%)	50.10	50.11	55.38	47.20	46.25	51.65	47.37	73.17
Hydrogen (%)	7.03	6.01	6.51	5.56	5.74	6.10	5.73	5.01
Nitrogen (%)	4.56	0.26	0.27	0.34	0.11	0.19	0.44	1.62
Oxygen (%)	37.44	40.48	35.98	45.20	39.06	41.57	42.50	6.41
Fluorine (ppmw)	<10	<10	<10	<10	<10	<10	---	30
Chlorine (%)	0.09	0.02	0.02	0.02	0.09	0.03	0.00	0.10
Mercury (ppmw)	0.09	<0.02	<0.02	0.03	<0.02	<0.02	---	0.15

3.3. Fuel receiving and handling

Refer to Figure 3 below. Woody biomass deliveries will be made in shipments of approximately 100 railroad cars per shipment to the proposed site that is already serviced by rail. The 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.

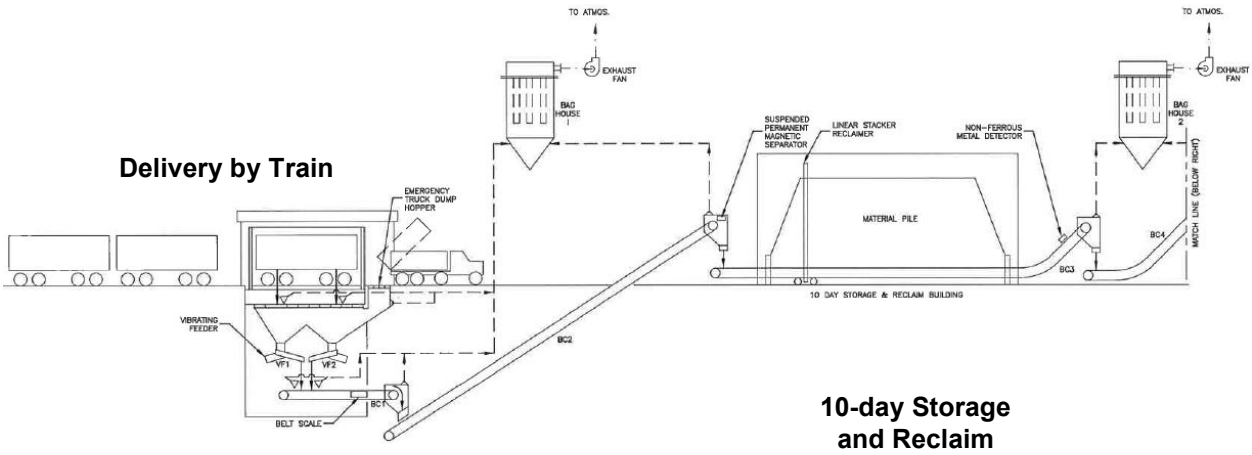

Figure 3. Woody biomass receiving, storage, and conveyance to dryer.

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. There will be baghouses at key transfer points.

From the fuel storage building, the fuel will be conveyed as shown in Figure 4 to a dryer where the moisture is reduced from as high as 37 percent (%) to approximately 23% by contact with preheated air. Incoming air will be indirectly heated by contact with steam coils supplied with process steam.

The moist air leaving the system will be filtered through a baghouse and exhausted to the ambient air. The lower moisture biomass will be conveyed from the dryer via a covered conveyor system to the gasification process area where it is stored in a metering/storage bin. Approximately 730 dry tons per day (TPD) of biomass will be fed to the gasifier.

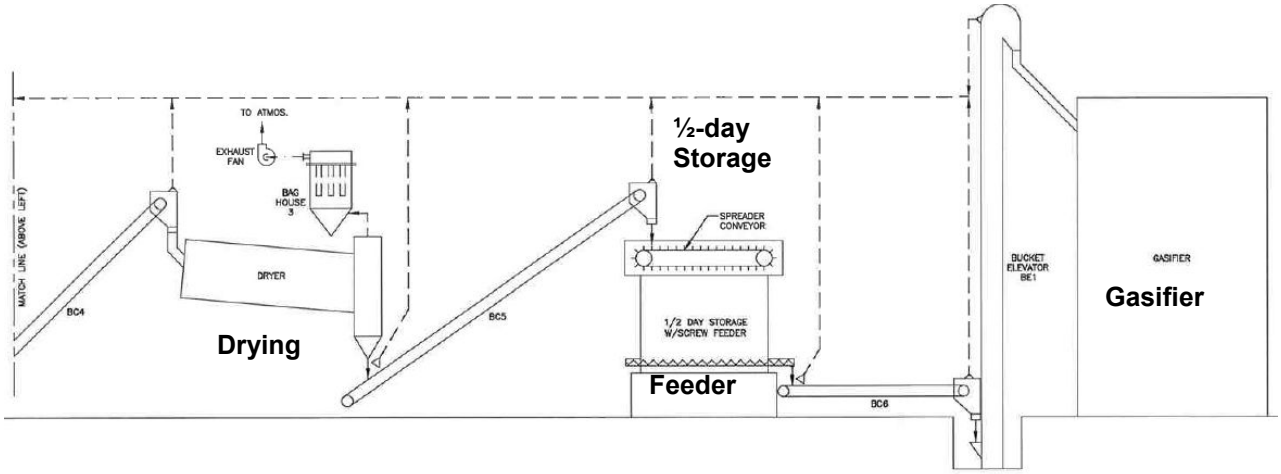

Figure 4. Woody biomass drying, conveyance and feeding to gasifier.

Gasifier/Combustor

This project is the first relatively large commercial application of a low pressure gasifier in a woody biomass-fed IGCC process or BIGCC. The SilvaGas gasification system consists of two sections; a gasifier into which the biomass is fed and a char combustor in which the char and tar are combusted to provide heat to the gasifier and the woody biomass dryer.

For reference, the gasifier/combustor arrangement shown in Figure 5 was invented by Battelle Laboratories and is called "SilvaGas". Batelle operated a pilot scale unit between 1980 and 2000 coupled to a very small (0.2 MW) CT.

Unlike other gasification processes, SilvaGas is not based on starved combustion (partial oxidation) whereby *some* oxygen (O_2) is supplied in nearly pure form (O_2-blown) or as air (air-blown). Instead, the biomass is subjected to steam and rapidly converted (pyrolized) to BPG in the absence of oxygen within a CFB of sand.

The heat for pyrolysis is derived from other parts of the process; most notably char combustion as described below, and low pressure steam from the STG. The hot sand imparts heat to the biomass and supports gasification. The steam serves as the gasification medium and participates in the pyrolysis reactions.

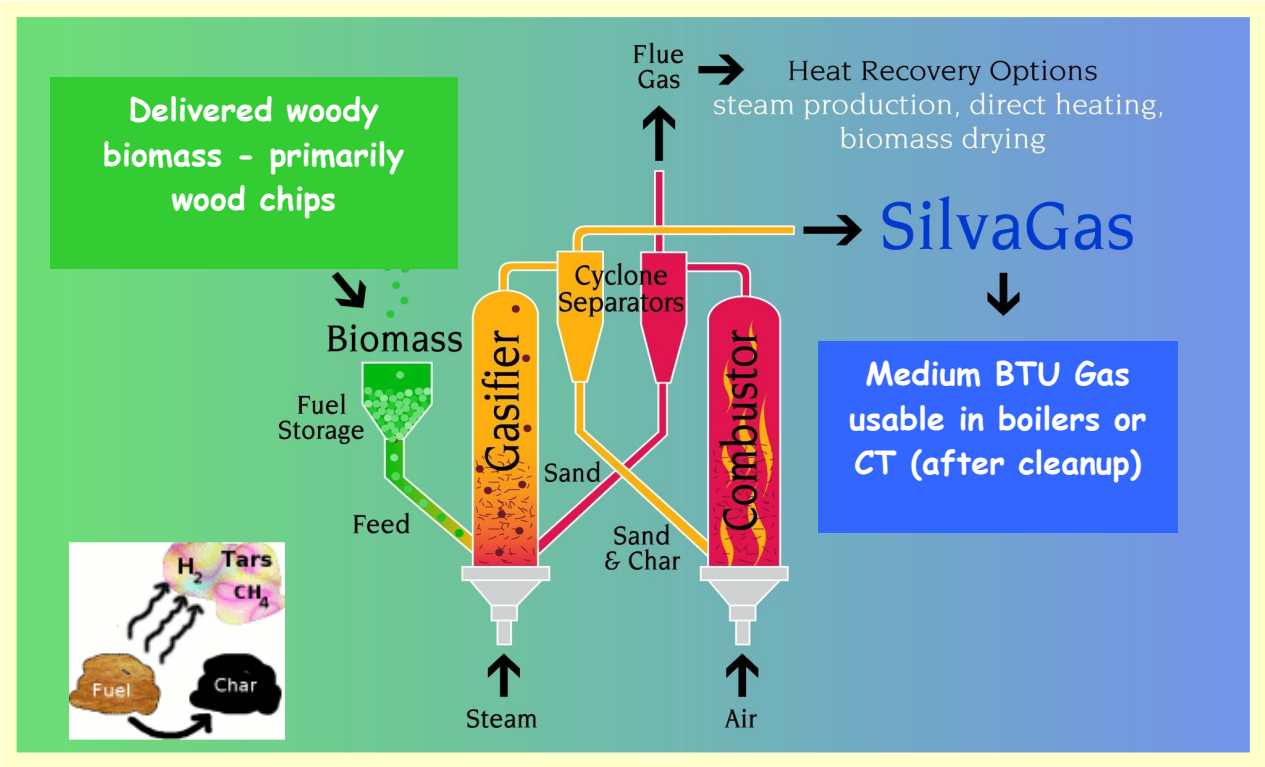

Figure 5. Gasifier/Combustor Section of the SilvaGas Process and Exhaust streams.

During the process, the sand cools and the biomass feed breaks down to produce BPG, char (nearly pure carbon), ash and condensable organic compounds referred to as "tar". The gasification proceeds as follows:

Equation 1: The primary products from the gasifier section are:

$$C_aH_bN_cO_dS_eX_f + H_2O + \text{hot sand} \rightarrow CO,\ H_2,\ CH_4,\ N_2,\ NH_3,\ H_2S,\ HCl,\ \text{char, tar, ash, cooled sand}$$

The subscripts (a, b, etc.) on the left are variable depending on the type of fuel. "X" represents miscellaneous species. The proposed gasification process operates at a relatively low temperature (~ 1400 °F) and pressure (near atmospheric) compared with higher temperature, high pressure air-blown or pure O_2-blown coal gasification processes.

Within the extreme reducing conditions in the gasifier, most fuel-nitrogen is converted to NH_3. The NH_3 concentration in the exit BPG depends on the time-temperature history of the gas in the gasifier.[2] Longer residence time at high temperature (~1,850 °F or greater) would favor removal of NH_3 by:

Equation 2. Thermal <u>decomposition</u> of NH_3 is described by the following global equation:

$$2NH_3 + heat \leftrightarrow N_2 + 3H_2$$

The relatively low operating temperature of the gasifier vessel (closer to 1,400 than 1,850 °F) results in less NH_3 decomposition in the SilvaGas process compared with higher temperature gasifiers, other factors being equal. However, the low N_2 content of the gas (due to lack of atmospheric nitrogen) would favor the forward reaction. Unless scrubbed, NH_3 reaching the CT and DB is converted to NO_X.

The BPG (also containing the uncondensed tars) emanating from the gasifier is subsequently cleaned as described below and is ultimately burned in the CT and DB. The char and cooled sand are separated from the BPG exiting the gasifier in dual, two-stage gasifier cyclones. The sand, char and tars (returned from downstream BPG cleaning) are then fed to the combustor. Air is introduced at the bottom of the vessel and supports conventional combustion of the char and tars in a CFB of sand and an oxidizing atmosphere at approximately 1615 °F.

Equation 3: The primary products from the combustor section (oxidizing atmosphere) are:

C_aX_b *(char)*$+C_aH_bO_c$ *(tar)*$+O_2$ *(air)+cool sand*$\rightarrow CO_2$, CO, NO_X, N_2, H_2O, *char, ash, hot sand*

Most sand and unburned char is captured in the cyclones and returned to the gasifier. Make up sand must be added to the process at an estimated rate of 300 lb per day (lb/day). The ash is a waste product that will be continuously removed and disposed off-site in accordance with applicable Department regulations.

The gasifier/combustor technology was purchased and then commercially demonstrated by Future Energy Research Company (FERCO) at the wood-fueled Burlington Electric Department (BED) Joseph C. McNeil Generating Station in Burlington, Vermont (McNeil Station). FERCO is the predecessor of BG&E.

At the McNeil Station, the BPG from the 200 TPD demonstration project augmented the wood fuel burned in an existing conventional boiler at the plant. A magazine article description of the program at McNeil Station is available at:

www.memagazine.org/backissues/membersonly/dec01/features/preaching/preaching.html

The photographs and the gasifier/combustor diagram shown below were taken from the article.

Figure 6. External Views and Internal Diagram of Gasifier/Combustor at McNeil Station.

A technical report describing the design, engineering, construction and startup at McNeil Station was prepared in 1998 by FERCO, BED, the Department of Energy National Renewable Energy Research Laboratories (DOE NREL) and Batelle.[3] It is available at:

www.gasification.org/Docs/Conferences/1998/gtc9823.pdf

The same authors prepared a technical report in 2000 describing the preliminary operating results at McNeil Station.[4] According to the authors, "operation at the McNeil site has validated the expected performance of the FERCO gasification process and has shown that:

- A medium heating value product gas can be produced from biomass without the use of pure oxygen;
- High biomass throughputs can be achieved in compact reactors; and
- No environmental problems exist with the technology."

The findings above are limited to the gasification system including the combustor. The project at McNeil Station did not demonstrate a cleanup system or the use of the BPG in medium sized CT such as proposed for the TREC. Operation of the gasification system was discontinued at the McNeil Station - at least for economic reasons. BED continues to operate the McNeil Station as a conventional wood-fueled power plant.

BG&E recently obtained an air construction permit from the State of Georgia to construct a gasifier/combustor in Forsyth County. The gasifier and combustor will operate more in the manner of the arrangement at McNeil Station (conventional boiler/steam generation) than in the manner of the proposed TREC (integrated with HRSG/CT).

The proposed gasification system at the Forsyth County site will process 900 TPD of biomass on a wet basis. It is rated at 372 million Btu per hour (mmBtu/hr) heat input, which is equal to the rating of the TREC gasification system.

An overall process diagram provided by BG&E for the proposed TREC is reproduced below and includes: the gasifier/combustor section on the left hand side; the proposed BPG cleanup system in the middle; and the power generation section on the right.

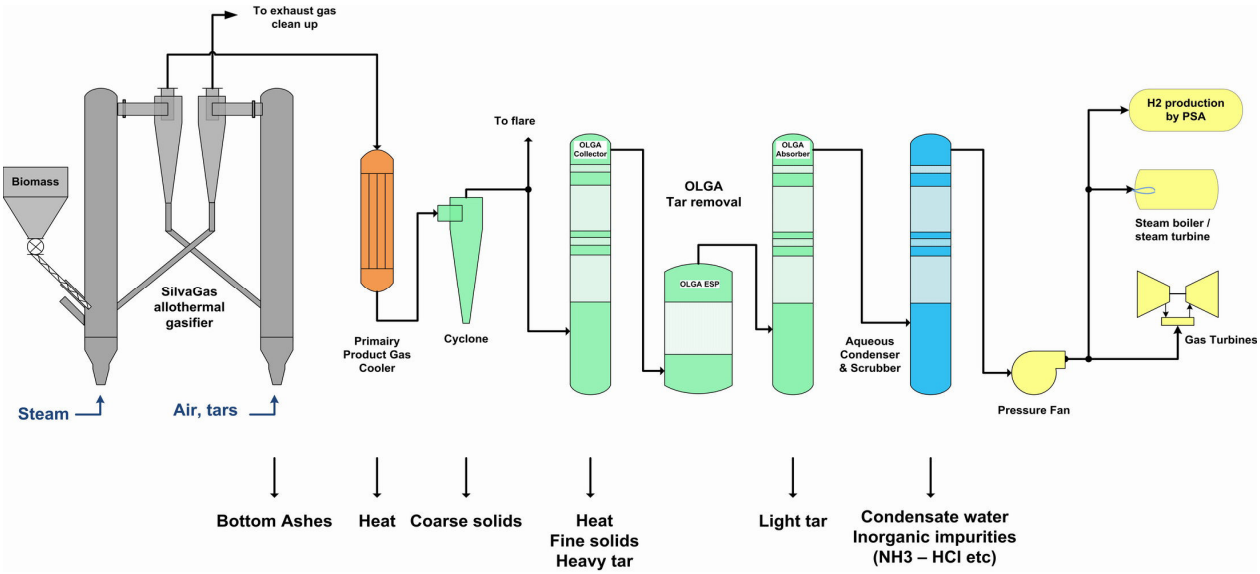

Figure 7. SilvaGas Gasifier/Combustor, BGP Cleanup System and Power Generation.

3.4. Char Combustor Exhaust Gas Cleanup

Char exhaust gas contains little SO_2 because most sulfur leaves the gasifier as H_2S in the raw BPG. Similarly, most of the nitrogen compounds (e.g. NH_3) leave with the raw BPG and are less available for conversion to NO_X in the combustor section. The temperature in the combustor (~1615 °F) is not conducive to thermal NO_X formation compared with the CT.

Most sand, ash and unburned char departing with the char combustor exhaust will be removed in the cyclones directly attached to the combustor and directed to the gasifier. The rest of the char combustor exhaust gas cleanup system is not shown in the above diagram.

Exhaust from the combustor cyclone passes through another cyclone to remove ash and then enters a heat exchanger that is used to produce steam that is fed directly to the STG. The cooled exhaust gas will then pass through a FF baghouse and exhausted to the atmosphere.

3.5. Removal of Tars and Particulate Matter from BPG

The raw BPG and the entrained ash that is not captured in the gasifier cyclone are cooled in a heat exchanger system fed by HRSG feedwater. The resulting steam is fed directly to the STG. The raw BPG passes through a cyclone where coarse particles are removed at temperatures greater than 750 °F which is also greater than the dew point of the heavier components of tars. From that point, the raw BPG can be flared or further cleaned up for use in the CT.

The presence of tars in the BPG is one of the biggest challenges to commercial application of BIGCC. The tars formed in the gasifier comprises a wide spectrum of straight, branched or ringed organic compounds that can be simply characterized as "heavy tars" and "light tars".

Heavy tars condense out as the gas temperature drops and can cause major fouling, efficiency loss and unscheduled plant stops. If not removed, tars can confound schemes to use BPG in applications such as fueling CT. The moisture and tar dew points are critical factors.

The key BPG cleanup system shown in the above diagram is known by the Dutch acronym for "oil-based gas washer" or "**OL**ie **GA**sswasser" (OLGA). The main purpose of OLGA is to remove tars and finer particles from the BPG. The process consists of the following four steps:

1. Heavy tars are condensed upon cooling in an oil scrubber;
2. Fines particles and entrained oil are removed in a wet electrostatic precipitator;
3. Light tars are captured in an absorber; and
4. The oil in the absorber is regenerated in a stripper with air.

The function of the OLGA system and its operating range within the cleanup system is shown in the figure below on the left hand side.

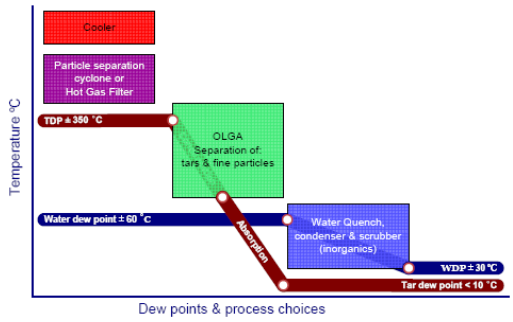

Figure 8. Function of OLGA. Wood pyrolysis tar. Naphthalene pluggage of valves.

The OLGA system lies between the BPG cooler described above and the further water scrubbing described below. The picture in the middle is an example of heavy tar from wood pyrolysis. The picture on the right hand side is of naphthalene crystals from light tars formed on fuel control valves. The OLGA system should remedy such problems. Tar removal is also necessary to prevent fouling in the subsequent wet scrubbing system that would otherwise occur.

According to BG&E, Hg will be converted to the elemental state [Hg(o)] in the gasifier rather than oxidized states. Because of temperature considerations, the Hg will follow the BPG stream rather than the char stream.

The OLGA system operates at temperatures greater than the dew point of water, so the vapor pressure of the Hg remains high. It is possible some amount will be returned to the combustor via tars reintroduced to the combustor; however most Hg should depart with the treated BPG from the OLGA system. Similarly, most nitrogen and sulfur compounds (primarily NH_3 and H_2S) will also leave with the treated BPG.

OLGA was developed at the Energy Research Center of the Netherlands (ERCN) circa 2001 specifically for BIGCC applications. The process underwent bench scale and small pilot scale proof of concept demonstrations with the assistance of the Dahlman Industrial group. The findings are summarized in a 2005 report by ERCN available at:[5]

www.ecn.nl/docs/library/report/2005/c05009.pdf

The largest known application of the OLGA system was constructed in Moisannes, France. It is used to clean at least some of the BPG produced from a wine residue and saw dust biomass gasifier. The cleaned BPG from the OLGA system is used to run a 1 MW gas engine-electric generator. The early details are given in a report by ERCN and Dahlman available at:[6]

www.renewableenergy.nl/index.php?pageID=3222&n=546

The photograph on the left hand side of the figure below shows the OLGA system at the Moisannes location. The photograph on the right is of a physical model of an OLGA system.

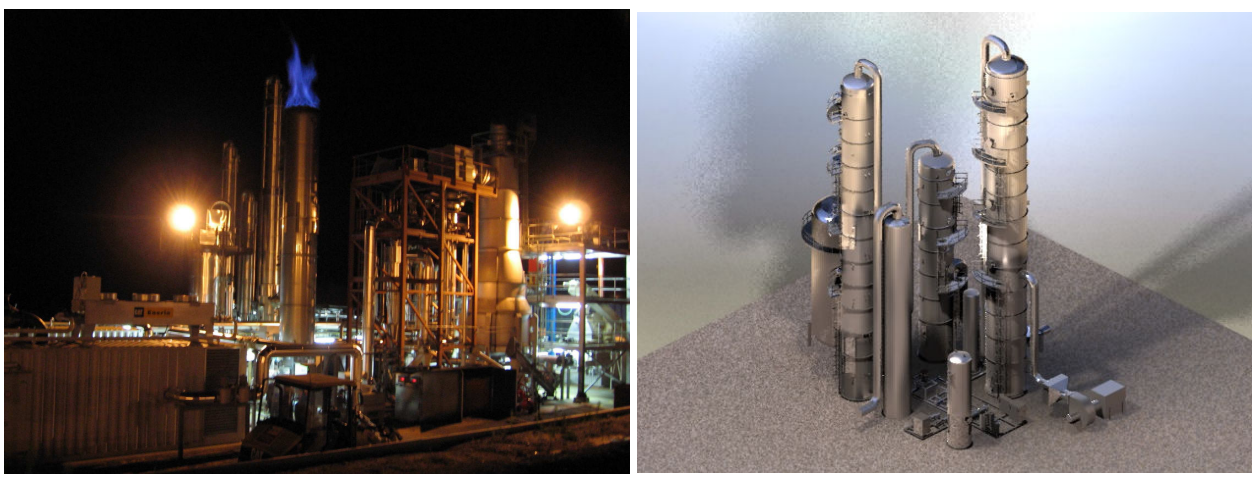

Figure 9. OLGA demonstration in Moisannes, France. Physical model of OLGA.

3.6. BPG Scrubbing

Before combusting the BPG in the CT it is still necessary to reduce the relatively small amounts of NH_3, H_2S and hydrogen chloride (HCl) contained in the treated BPG from the OLGA system. The removal will be accomplished in a wet scrubber at the tail end of the BPG cleanup process. Although the scrubber design is not yet finalized, the wet (water) scrubber will readily absorb and dissolve gaseous NH_3 and HCl. The scrubber will include a section that will scrub H_2S using caustic soda (NaOH). In addition, the scrubber may remove some Hg.

Equation 4. The acid-base removal of H_2S is accomplished as follows:

$$2NaOH + H_2S \leftrightarrow Na_2S + H_2O$$

Normally Hg(o) is not readily removed by scrubbing with water. However, according to BG&E, Hg(o) will react with H_2S in the first section of the scrubber and precipitate as mercuric sulfide (HgS) that will be filtered in the main recirculating water loop.

BPG will leave the cleanup system at approximately 110 °F and 10 pounds per square inch, gauge pressure (psig). It will be split between two compression and CT trains.

3.7. BPG and Natural Gas Firing in CT

BPG Delivered for Combustion

Cooled, sweetened, cleaned BPG is compressed in a pair of two-step BPG compressors and delivered to the CT. The characteristics of the BPG are given in Table 3. The characteristics of natural gas and of synthesis gas from two coal gasification schemes are also given.

The cleaned BPG can be described as medium heating value fuel. Its characteristics are closer to those of the cleaned synthetic gas (syngas) from an oxygen (O_2)-blown coal gasifier. The observation is based on the very low N_2 levels. The reason that N_2 is low in the O_2-blown coal syngas is that (in contrast to air-blown syngas) it is separated from the air used in the gasifier and is not carried through the system. The reason that N_2 is low in BPG is that the woody biomass is not exposed to air, but rather steam, when effecting pyrolysis.

Table 3. Exhaust Characteristics of Unit B at 100% Load and Reference Temperature.

Constituent	Percent (%) as Delivered to Combustion Turbine
Hydrogen (H_2)	20.7
Carbon Monoxide (CO)	45.8
Methane (CH_4)	15.61
Carbon Dioxide (CO_2)	11.03
Water (H_2O)	0.22
Nitrogen (N_2)	0.68
Other (e.g. ethane, etc.)	0.68
LHV (Btu/standard ft^3)	435

Description of CT

BPG or back-up/startup natural gas will be fired in a CT. A CT is an internal combustion engine that operates with rotary rather than reciprocating motion. They are often called gas turbines because air is the working medium (as opposed to steam).

The applicant proposes to use two nominal 14.8 MW Solar T-130 CT. Each CT will have a maximum heat input of 145 million Btu per hour, lower heating value (mmBtu/hr, LHV) when firing BPG. Figure 10 shows an existing gas-fueled combined cycle located in Spain and based on the Solar T-130 design used to dry biomass for combustion in a boiler. It also shows an internal diagram from Solar of the compressor, combustor and rotor sections of a CT.

How the CT Works

Ambient air is drawn into the 14-stage compressor of the T-130 and is compressed to a pressure ratio of 16 times atmospheric pressure. The compressed air is directed to the combustor section, where the fuel from the BPG compressors is introduced, ignited, and burned.

Figure 10. Gas-fired unit with Solar T-130 CT. Diagram of compressor and rotor sections.

The hot combustion gases are then diluted with additional cooling air and directed to the rotor (expansion) section. Energy is recovered in the rotor section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load, which in this case is an electrical generator. Turbine exhaust gas (TEG) is discharged at approximately 925 °F.

Without further heat recovery, the efficiency of the CT is on the order of 37.5% based on the electrical energy produced compared with the energy in the delivered BPG.

Evaporative Cooling (EC) or "Fogging"

In addition to the DB feature, the applicant proposes to include a feature whereby fine water droplets are introduced into the CT compressor inlet air. The practice reduces the compressor inlet air temperature and, in turn, results in greater mass flow rate through the CT turbine with a boost in electrical power production.

The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging is typically practiced at ambient temperatures of 60° F or higher.

How the HRSG and Steam Turbine-Electrical Generator (STG) work

The heat content and high excess oxygen of the TEG are available to support BPG combustion in the DB located within each HRSG and to provide energy to raise steam and produce additional electricity in the STG. Each DB will be rated at 28 mmBtu/hr (nominal). In addition to steam raised from TEG and DB exhaust, additional steam produced in the heat exchangers within the gasifier island will also be fed directly to the STG. The arrangement whereby steam is raised using the TEG is known as a combined cycle. An example of a combined cycle unit fueled by natural gas is shown in Figure 11 below.

The further integration of the CT/HRSG/DB/STG components with the steam generated from the biomass gasifier and char combustor heat exchangers results in a high degree of integration, hence the term BIGCC. According to BG&E the overall efficiency of the BIGCC is greater than 40% which is superior to conventional coal combustion power cycles.

The overall efficiency of a BIGCC will be less than the standard combined cycle firing natural gas. This is due to the various transformations of the basic fuel, pressure drops, additional BPG compression, heat losses through liquid and solid effluents and the basic laws of thermodynamics. The expectation is that the proposed project will achieve overall (net) 40% efficiency on a higher heating value (HHV) basis.

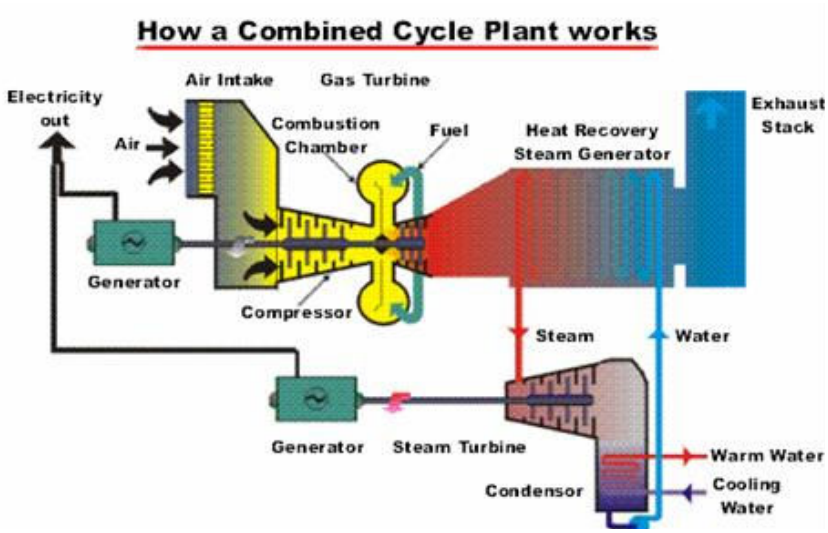

Figure 11. A conventional natural gas fueled combined cycle unit.

4. RULE APPLICABILITY

4.1. Federal Regulations

This project may be subject to certain provisions regarding air quality established by the Environmental Protection Agency (EPA) in the Code of Federal Regulations (CFR), including:

Title 40	Description
Part 60	New Source Performance Standards: 40 CFR 60 Subparts A, Dc and KKKK
Part 70	State Operating Permit Programs
Parts 72,73	Acid Rain – Permits, SO_2 Allowance System
Parts 75-77	Acid Rain – NO_X Emissions Reduction Program, Excess Emissions

4.2. State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the F.A.C.

Chapter	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Requirements For Sources Subject To The Federal Acid Rain Program
62-296	Stationary Sources - Emission Standards
62-297	Stationary Sources - Emissions Monitoring

4.3. Potential Emissions and PSD Non-Applicability Determination

The Department regulates major stationary sources of air pollution in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. Per Rule 62-210.200(Definitions), F.A.C., a major stationary source is

1. Any of the following stationary sources of air pollutants which emits, or has the PTE, 100 TPY or more of any PSD pollutant:
   - Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input,
   - Coal cleaning plants (with thermal dryers),
   - Kraft pulp mills,
   - Portland cement plants,
   - Primary zinc smelters,
   - Iron and steel mills,
   - Primary aluminum ore reduction plants,
   - Primary copper smelters,
   - Municipal incinerators capable of charging more than 250 TPD of refuse,
   - Hydrofluoric, sulfuric, or nitric acid plants,
   - Petroleum refineries,
   - Lime plants,
   - Phosphate rock processing plants,
   - Coke oven batteries,
   - Sulfur recovery plants,
   - Carbon black plants (furnace process),
   - Primary lead smelters,
   - Fuel conversion plants,
   - Sintering plants,
   - Secondary metal production plants,
   - Chemical process plants,
   - Fossil-fuel boilers (or combination thereof) totaling more than 250 mmBtu/hr heat input,
   - Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels,
   - Taconite ore processing plants,
   - Glass fiber processing plants,
   - Charcoal production plants;
2. Any stationary source which emits, or has the PTE, 250 TPY or more of a PSD pollutant; or
3. Any physical change that would occur at a stationary source not otherwise qualifying as a major stationary source, if the change would constitute a major stationary source by itself.

The category of BIGCC is not among the bulleted stationary sources listed in paragraph 1. above that would be classified as a major stationary source based on the PTE 100 TPY of a PSD pollutant. The proposed TREC is not an existing stationary source and not subject to paragraph 3. above. To be considered a major stationary source, it would be necessary for annual emissions of a PSD pollutant from the TREC to equal or exceed 250 TPY.

The project will (at least) result in emissions of NO_X, CO, particulate matter (PM, PM_{10} and $PM_{2.5}$ - for which PM_{10} is a surrogate), SO_2, and small amounts of sulfuric acid mist (SAM), VOC and hazardous air pollutants (HAP). Table 4 summarizes the applicant's estimates of key pollutants including those from the CT, DB, char combustor, flares, material handling, an auxiliary boiler and cooling towers.

No PSD pollutant emissions will equal or exceed 250 TPY, based on operation design and associated emission limits. Therefore, the TREC will not be subject to the PSD rules including PSD ambient air modeling or a requirement for a best available control technology (BACT) determination under that program.

Table 4. Applicant's estimate of annual emissions from the BG&E TREC in TPY.

Pollutant	CT/DB	Char Combustor	Cooling Towers	Material Handling	Aux. Boiler	Flares	Dryer	Total
SO_2	72	11	0	0	0.09	0.80	0	83
PM	63	27	0.04	24	0.03	Neg	0.10	114
PM_{10}	63	27	0.04	24	0.03	Neg	0.01	114
NO_X	167	27	0	0	1.47	0.70	0	197
CO	188	11	0	0	1.24	3.8	0	204
VOC	11	6	0	0	0.08	1.5	0	18
SAM	<4	<3	0	0	Neg	Neg	0	<7
HAP	4	1	Negligible (Neg)					5
Hg	Neg	2 lb/yr	Neg					2 lb/yr
NH_3	23	Emissions from CT/DB are "slip" from SCR. Rest assumed neg.						23
Fluoride (F)	Neg							~0
Lead (Pb)	Neg							~0

4.4. New Source Performance Standards and National Emissions Standards for HAP

The CT and the DB located in the HRSG are subject to 40 CFR 60, Subpart KKKK as cited above. The emission standards for the size category of the CT that will be used at the TREC (> 50 mmBtu/hr and ≤ 850 mmBtu/hr) are given in the following table and also account for DB emissions.

Table 5. Emission standards applicable to TREC based on 40 CFR 60, Subpart KKKK

New CT Type	NO_X Emission Standard	SO_2 Emission Standard
Firing natural gas	25 ppmvd @15% O_2	0.060 lb SO_2/mmBtu
Firing fuels other than natural gas	74 ppmvd @15% O_2	

Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring when using natural gas by demonstrating sulfur content of no more than 20 grains/100 standard cubic feet (gr/SCF) of natural gas.

40 CFR 60, Subpart A – General Provisions are applicable to the affected sources for which standards have been promulgated under Section 111, Clean Air Act. The sources subject to Subpart KKKK are therefore also subject to Subpart A. In addition to the emission standards in Subpart KKKK, the two subparts include requirements for notification, record keeping, performance testing, and monitoring of operations that are applicable to the TREC.

Subpart KKKK will be the primary basis for the permit conditions related to the CT and DB, especially since a BACT determination is not required. Some provisions in addition to Subpart KKKK are included in the draft permit conditions to limit the PTE individual PSD pollutants from the entire facility to less than 250 TPY. These include, for example, 12-month rolling average limitations on NO_X and CO.

The applicant has proposed a NO_X limit of 32.5 ppmvd @15% O_2 on a 30-day rolling average when burning BPG instead of the Subpart KKKK values of 74 ppmvd @15% O_2 cited above. The lower emission concentration value will effectively limit PTE from each HRSG (CT/DB) stack to approximately 19.2 pounds per hour (lb NO_X/hr) and to 167 TPY from the two HRSG stacks combined.

Because the TREC is not a major source of HAP, it will not be subject to any regulations pursuant to 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP) for source categories. Among the key provisions that do not apply are those of 40 CFR 63, Subpart YYYY - NESHAP for Stationary Combustion Turbines. Even if the TREC were a major source of HAP, the applicability of Subpart YYYY has been stayed for lean premix and diffusion flame gas-fired CT including the type planned for this project.

Startup burners for the gasifier and the char combustor are required. The two burners will have nominal ratings of 25 and 17 mmBtu/hr, respectively. These burners will operate on the order of 14 hours each during cold startup and will slowly heat olivine, gasifier and combustor surfaces, heat exchangers, and eventually feedwater thus producing steam.

The function of these devices appears to fit within the definition of a *steam generator unit* as the term is used in 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

"Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other transfer medium ….. This term does not include process heaters as defined in this subpart.

"Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst."

Besides heating vessel surfaces, ducts, water (producing steam) the two burners also heat olivine. The heated olivine initiates the pyrolysis of the woody biomass. In certain applications, though not in this one, olivine impregnated with nickel breaks down tars. In the present application, it does not participate as a reactant or as a catalyst. Therefore, the burners are not exempt from Subpart Dc.

An auxiliary boiler with a nominal capacity of 62 mmBtu/hr will be included in the project for the purpose of providing steam as the conveyance medium in the gasifier during startup. It will also provide steam to preheat the STG during startup. The auxiliary boiler is clearly subject to Subpart Dc.

The Department also considered the applicant's assertions that none of the following federal regulations are applicable to the TREC and concluded (after informal consultations with various offices of EPA) that they do not apply to the TREC:

- 40 CFR 60, Subpart Eb - Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996.
- 40 CFR 60, Subpart CCCC - Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001.
- 40 CFR 60, Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes.

EPA will have the opportunity to review the Department's conclusion prior to issuance of the final decision for this project.

4.5. Other Department Rules Potentially Applicable to the Project

The Department reviewed the following regulations and concluded that they do not apply to the TREC:

- Section 62-296.401, F.A.C. - Incinerators;
- Section 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment; and
- Section 62-296.416, F.A.C. - Waste-to-Energy Facilities.

Incinerators and waste to energy facilities combust waste. The fuel slate authorized by this permit does not constitute a waste or municipal solid waste.

Carbonaceous fuel is defined in Rule 62-210.200, F.A.C. as "solid materials composed primarily of vegetative matter such as tree bark, wood waste, or bagasse". Although such materials are pyrolized (not burned) to make BPG and char, the resulting products that are subsequently combusted do not meet the definition.

5. EMISSIONS FORMATION AND CONTROL

5.1. NO_X Formation

NO_X forms in the CT as a result of the dissociation of molecular N_2 and O_2 to their atomic forms and subsequent recombination into seven different oxides of nitrogen. It also forms by oxidation of nitrogen present in the fuel.

Thermal NO_X. Thermal NO_X forms in the high temperature area of the CT combustor as seen on the left hand side of Figure 12.

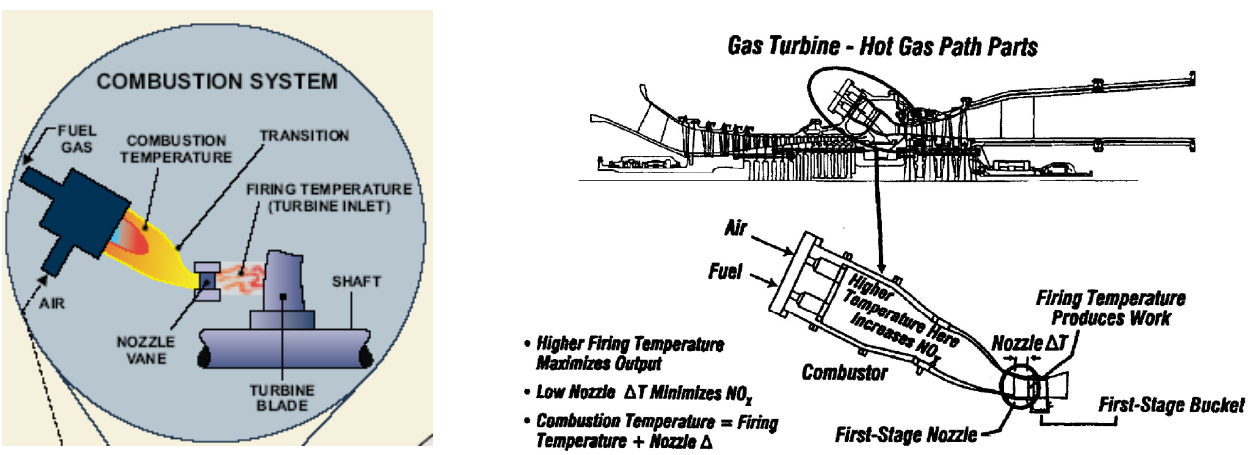

Figure 12. Relation between Combustion and Firing Temperatures and NO_X Formation.

Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 12, which is from a GE discussion on these principles.

In all but the most recent CT combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle.

Uncontrolled emissions can range from about 100 to over 600 parts per million by volume, dry, corrected to 15% O_2 (ppmvd @15% O_2) depending upon design. The applicant estimates uncontrolled emissions at approximately 325 ppmvd @15% O_2 from the CT for this project.

On the other hand, thermal NO_X concentrations from the char combustor will be relatively low because combustion occurs in a CFB at approximately 1615 °F which is about 1000 °F lower than the temperature at which thermal NO_X formation is of significance.

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion. Prompt NO_X formation within the CT combustor is believed to be minimal. Prompt NO_X is not important in the char combustor because there is no flame front in the CFB.

Fuel NO_X is formed when fuels containing bound nitrogen or reduced nitrogen compounds (such as NH_3) are burned. This phenomenon is not important when the unit fires natural gas or when NH_3 has been removed in BPG prior to combustion. However the presence of NH_3 is the critical consideration in the proposed project when firing syngas.

Fuel NO_X is not important in the char combustor because the char is practically devoid of nitrogen.

5.2. NO_X Control

There are several NO_X reduction processes available without the need to install add-on control equipment. These include varieties of staged combustion or wet injection of diluent to control NO_X formation. The Solar version of dry low NO_X (DLN) combustion is called $SoLoNO_X$. As noted above, emissions from the CT/DB will be 325 ppmvd @15% O_2 indicating that neither wet injection nor $SoLoNO_X$ are planned for the TREC. Presumably this is related to the heating value of the BPG and the need to maintain stable combustion with possibly variable fuel properties (ultimately based on variability of woody biomass).

The applicant will install SCR, which is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst.

Equation 5. NH_3 reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations.

There are numerous combined cycle units that have been constructed in Florida that incorporated SCR systems. Most recently, the Department issued permits for Florida Municipal Power Agency (FMPA) Treasure Coast Energy Center, FMPA Cane Island Unit 4, Florida Power & Light West County Energy Center and Orlando Utiltities Commission Stanton Unit B with NO_X limits of 2.0 ppmvd @15% O_2 on natural gas.

The Department has reasonable assurance that the TREC project can achieve the long term reduction (typically 90%) to consistently meet the levels necessary to meet both the Subpart KKKK limits of 74 and 25 ppmvd @15% O_2 for BPG and natural gas respectively. The applicant has requested a BPG-based limit of 32.5 ppmvd to provide reasonable assurance that the PTE NO_X from the facility will be less than 250 TPY.

Figure 13 (Nooter-Eriksen) is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the NH_3 injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure 14 is a photograph of the Progress Energy Florida (PEF) Hines Power Block I, which is much larger than the proposed TREC. The external lines to the NH_3 injection grid are easily visible. SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive NH_3 use can increase emissions of CO, NH_3 (slip) and $PM_{10}/PM_{2.5}$ when sulfur-bearing fuels are used.

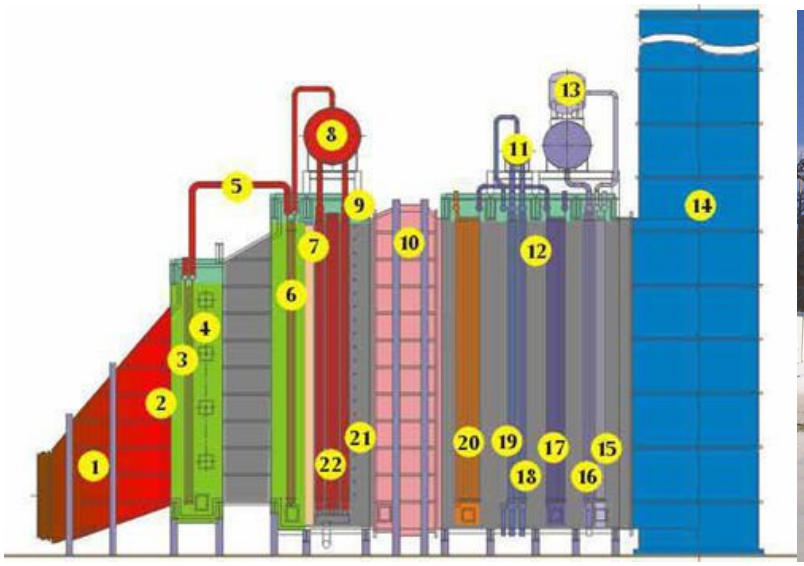

Figure 13 – Key HRSG Components (10 is SCR).

Figure 14 – PEF Hines Block I.

The low NO_X formation potential of the char combustor (due to relatively low char nitrogen and low firing temperature) was addressed in Section 3.4 above. In contrast to the CT/DB, additional NO_X controls are not needed. The applicant estimated NO_X emissions from the char combustor at 27 TPY (approximately equal to 6 lb/hr).

The Department will conservatively assume for the purposes of this review that NO_X emissions from the char combustor will be approximately 10 lb/hr and 44 TPY. The Department will require annual testing of the char combustor to provide further assurance and to verify that (in conjunction with emissions from the CT/DB) the facility-wide emissions of NO_X will be less than 250 TPY.

5.3. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Formation and Control

The main control for SO_2 for the TREC is the prevention of its formation through use of low sulfur feed and fuel. All of the biomass sources given in Table 2 contain much less sulfur (S) than bituminous coal which contains 1.52 percent as shown in Table 2.

As previously discussed, sulfur is released as H_2S in the gasifier and is primarily contained in the BPG rather than the char. The wet scrubber in the BPG includes a caustic section that will remove H_2S as sodium sulfide (Na_2S).

SO_2 and SAM form from the small amount of H_2S reaching the CT and DB as a result of the oxidation (combustion) of sulfur-containing molecules.

Equation 6. H_2S present in the syngas combines with O_2 as follows:

$$2H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O$$

Equation 7. SO_2 is further oxidized depending on the presence of temperature, O_2, and water vapor to yield SAM by the following reactions:

$$2SO_2 + O_2 \rightarrow 2SO_3 \quad \text{and} \quad SO_3 + H_2O \rightarrow H_2SO_4$$

The applicant has estimated emissions of 8.2 lb SO_2/hr from each HRSG stack when burning BPG by assuming an exhaust gas concentration of 20 ppm by weight. This equates to annual emissions of approximately 36 TPY from each HRSG stack. Total emissions are estimated to be 16.4 lb/hr and 72 TPY from the two HRSG stacks and 83 TPY from the facility.

If it is assumed there will be on average 0.05% S (dry basis) in the incoming biomass (BM) and none is removed in the process, then the uncontrolled emissions would be equal to:

(730 tons BM/day)(0.0005 tons S/ton BM)(day/24 hr)(2000 lb S/ton S)(2 lb SO_2/lb S) = 61 lb/hr

This would require removal of approximately 75% of the sulfur in the BPG treatment system. This is a reasonable expectation based on the use of caustic scrubbing. The estimate of 16.4 SO_2/hr from the two HRSG (CT/DB) exhaust stacks equates to 0.043 lb SO_2/mmBtu which is within the value of 0.060 lb SO_2/mmBtu required by Subpart KKKK.

Adherence to the Subpart KKKK limit of 0.060 lb SO_2/mmBtu when firing BPG and to the optional Subpart KKKK limit of 20 gr S/100 standard cubic feet (SCF) when using natural gas will provide limit emissions of SO_2 to approximately 100 TPY. This will, in turn, provide reasonable assurance that the PTE SO_2 from the entire facility will be less than 250 TPY. This assumes low SO_2 emissions from the char combustor.

For reference, the Federal Energy Regulatory Commission (FERC) tariff allows 10 gr S/100 SCF and the natural gas typically available in Florida contains less than 1 gr S/100 SCF. Greater values are usually indicative of odorant addition rather than inherent S concentration.

5.4. CO and VOC Formation and Control

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The control techniques are based upon high temperature, sufficient time, turbulence and excess air.

Except for avoidance of PSD by emitting less than 250 TPY, there are no CO or VOC limitations from any specific air regulations (including Subpart KKKK) that are applicable to the TREC.

Emissions from the CT should be low given the high BPG firing temperature (that results in high pre-control NO_X emissions). Further firing of BPG in the DB is accomplished in an atmosphere of hot TEG, high O_2 content and turbulence. Typically under such conditions, CO concentrations, if not mass emission rates, are actually reduced by the DB.

The applicant estimated CO emissions from the char combustor at 2.6 lb/hr and 11.4 TPY. The basis was the combustion of anthracite coal that, like char, contains minimal amounts of volatile components. The CO emissions will depend a great deal on the residence time in the CFB within the char combustor and the extent to which it interacts with the tar from the OLGA process.

The Department will conservatively assume for the purposes of this review that CO emissions from the char combustor will actually be closer to 10 lb/hr and 44 TPY and will require measurement to provide further assurance and to verify that the facility-wide emissions of CO will be less than 250 TPY. A CO limit is also appropriate to insure good char burnout thereby minimizing HAP emissions. The Department will require installation of a CO process monitor and recordkeeping to insure implementation of good combustion practices.

Table 6. Projected CO and VOC from HRSG (CT/DB) and char combustor at TREC.

Location	Concentration (ppmvd)[a]		Mass Rate (lb/hr)		Annual Emissions (TPY)	
	CO	VOC [b]	CO	VOC [b]	CO	VOC [2]
CT outlet	50	25	17.2	4.9	75.5	21.5
DB contribution			4.2	1.6	18.3	6.9
One HRSG stack	48.3	25.6	21.4	6.5	93.8	28.4
Two HRSG stacks			42.8	13.0	187	57
Char Combustor			2.6 (10)[c]	1.3	11.4 (44)[c]	5.6
HRSG+Combustor			45 (53)[c]	14	198 (231)[c]	63

a. Corrected to 15% O_2.

b. VOC as unburned hydrocarbons (UHC).

c. Values in (parentheses) represent maximum limits proposed by the Department that also provide reasonable assurance that total facility emissions will be less than 250 TPY of CO.

The CO concentrations are moderate compared with single digit values achievable by large frame CT. The VOC values may be overstated because they are given as UHC that often include methane (CH_4) which is not recognized as a VOC.

The annual VOC emissions from the two HRSG stacks are sufficiently low to provide reasonable assurance that facility-wide emissions will be less than 250 TPY. Compliance with the CO emissions limits will suffice to demonstrate that CO and VOC emissions will each be less than 250 TPY for the facility.

Similarly VOC emissions could be less than or greater than estimated by the applicant. The Department will conservatively assume that VOC emissions will likely be 5 lb/hr and 22 TPY and rely on measurement of CO to insure both CO and VOC emissions will be emitted at levels less than 250 TPY from the facility.

If CO values exceed the emission limits, TREC may be required to install an oxidation catalyst system in the HRSG or implement measures to improve burnout from the char combustor.

5.5. NH_3 Emissions (slip)

The applicant did not propose an NH_3 emission limit or a maximum slip value in conjunction with the SCR system. In section 5.2 above the Department noted that emissions from the CT/DB are estimated by the applicant at 325 ppmvd @15% O_2 before and 32.5 ppmvd @15% O_2 after SCR control. This represents a reduction of 90%.

The Department routinely sets NH_3 limits of 5 ppmvd @15% O_2 for combined cycle projects that rely on SCR for NO_X control. Most of those projects control NO_X from the range of 9-42 ppmvd to 2-8 ppmvd. To achieve the much greater reduction in relative and in real terms, it will be necessary to insure sufficient excess NH_3 is used. The applicant expects NH_3 concentrations of 10 ppmvd.

The Department will set an NH_3 limit of 10 ppmvd @15% O_2. Estimated annual emissions from the two HRSG stacks will be less than 32 TPY. With the relatively low SO_2 emissions, the possibility of a visible plume will be minimal. There are no other specific NH_3 limits applicable to the facility and NH_3 is not a PSD pollutant.

NH_3 from char combustion will be minimal due to the fact that most NH_3 is contained in the BPG and the minimal NH_3 in the char and tar would be burned to NO_X.

5.6. Particulate Matter (PM/PM_{10}) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} emitted from combustion turbines are typically due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion. BPG and natural gas will be the only fuels fired and are efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperatures and pressures. Natural gas is an inherently clean fuel and contains no ash.

The BPG will contain gasifier ash prior to the cleanup system shown in Figure 7 above. The cleanup includes solids removal in the gasifier cyclone, the coarse solids cyclone and fine solids removal features of the OLGA system. Finally, efficient and high temperature combustion of the BPG in the CT and DB will minimize emissions of PM/PM_{10}.

The following table is a summary of PM_{10} emissions provided by General Electric to FP&L from their large frame GE 7FA units operating on natural gas.[7, 8] There is great variation in PM_{10} emissions even though the units are similar if not identical and all relied on the natural gas supply.

The applicant estimated PM/PM_{10} emissions from each HRSG stack at the proposed TREC at 7.2 lb/hr and 31.5 TPY. The estimates appear to be reasonable given the emissions from the order-of-magnitude larger GE7FA units cited in the following table.

Table 7. PM_{10} Emissions from GE 7FA Units Firing Natural Gas.

Fuel	Range (lb/hr)	Average (lb/hr)	~lb/mmBtu
Natural Gas - Front-half (filterable)	0 – 17	4.8	0 – 0.009
Natural Gas - Back-half (condensable)	0 - 15	14	0 - 0.008
Natural Gas Total	1 - 29	7.5	0.0005 - 0.016

The very high combustion temperatures, use of inherently clean natural gas or cleaned BPG, and inclusion of an NH_3 limit will insure that PM/PM_{10} emissions will be at least as low as estimated by the applicant.

The applicant estimates PM/PM_{10} emissions of approximately 6.0 lb/hr and 27 TPY from the char combustor. The estimates appear reasonable based on the sand recovery cyclone, an ash removal cyclone and a fabric filter baghouse. The applicant estimates PM/PM_{10} removal efficiency of 98% between the ash cyclone and the baghouse.

The Department will set a limit 10 lb/hr per HRSG stack and a visible emission standard of 10% opacity to provide continuous reasonable assurance of low PM/PM_{10} emissions that will be less than the PSD thresholds.

The applicant identified materials handling as the other main source of PM/PM_{10} emissions. The associated transfer point will be controlled by baghouses. The applicant estimates total facility PM/PM_{10} emissions at 114 TPY. Even with an emission limit of 10 lb/hr from each HRSG stack and from the char combustor, there would be reasonable assurance that annual PM/PM_{10} emissions will be less than 250 TPY.

The Department will also require installation of a continuous opacity monitoring system (COMS) on the char combustor exhaust stack and adherence to a 10% opacity standard to further minimize both visible emissions and particulate matter.

5.7. Mercury (Hg) Control

As noted in Table 4 above, estimated emissions of Hg are approximately 2 lb/yr. For reference, major stationary sources that exceed 250 TPY of a PSD pollutant must conduct a BACT determination for Hg if such emissions will exceed the significant emission rate (SER) of 200 lb/yr. The emissions rate from this facility will be about 1% of the SER.

5.8. Dioxin and Furan (D/F) Control

D/F constitute a class of cyclic halogenated hydrocarbons with halogen atoms (such as chlorine) substituting some of the points in the ringed structures normally occupied by hydrogen. Furthermore two ringed halogenated hydrocarbons are joined to each other in such a manner that involves at least one oxygen molecule.

Following is the example of 2,3,7,8 tetrachlorodibenzo-p-dioxin (2378-TCDD). A model of cellulose is included for comparison. The furan version would have just one oxygen molecule.

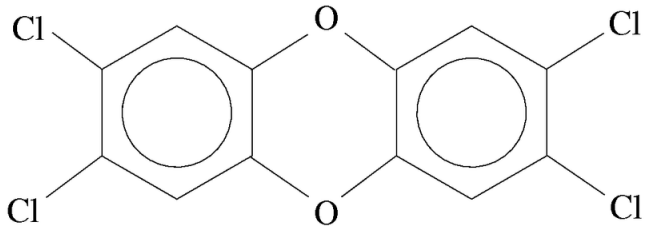

Figure 15 – Skeletal diagram of the 2,3,7,8 TCDD molecule.

The key to D/F control is to avoid its formation and promote its destruction. Woody biomass generally contains much less chloride than coal or municipal solid waste containing plastics. The relatively small amount of hydrogen chloride formed in the gasifier and contained in the raw BPG will be largely removed in the wet scrubber prior to combustion in the CT/DB.

Burning the BPG at high temperatures and with very high excess O_2 in the CT/DB will destroy any ringed structures including D/F. Finally SCR, such as incorporated into the TREC project, has been shown to be effective in the destruction of D/F. Significant opportunities for D/F to reform do not exist if for no other reason than the absence of chlorine in the scrubbed BPG.

The possibilities for dioxin emissions exist from the char/tar combustion. The raw BPG contains a variety of compounds including tars as discussed above. The tars are formed by the pyrolysis of cellulose, which is an organic compound $(C_6H_{10}O_5)_n$, consisting of a linear chain of several hundred to over ten thousand linked glucose units as shown below:

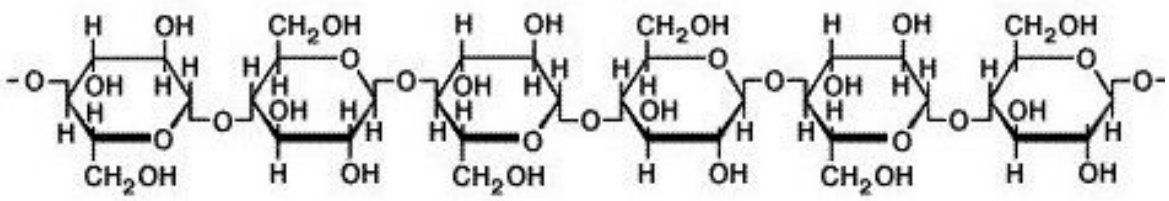

Figure 16 – Skeletal diagram of cellulose.

The breaking of the many ringed compounds provides the opportunity to form many types of ringed compounds that comprise tars. In the presence of chlorides, the opportunity for D/F formation exists.

These compounds (tars as well as any small quantities of D/F formed from the raw BPG) are removed by the OLGA system. According to the applicant, the oils used to scrub tars within the OLGA system are comprised of hydrocarbons that do not contain chlorine. The tars containing small amounts of D/F are fed to the char combustor.

There are a number of reasons that suggest relatively low D/F emissions from the char combustor exhaust. These include:

- Relatively low chlorides in the feedstock;
- Removal of most chlorides such as HCl in the wet scrubber system;
- Inherently low metal concentrations in the feedstock such as copper that can otherwise catalyze HCl to chlorine (Cl_2) for participation in D/F formation;
- Destruction of D/F in tars within the CFB of the char combustor;
- Maintenance of relatively high temperature with a long residence time from the char combustor through the riser and to the hot ash cyclone;
- Rapid cooling (quenching) in the heat exchanger that heats HRSG feedwater; and
- Further removal in the baghouse.

While it cannot be concluded that D/F emissions will be zero, it can be concluded that such emissions will be less than from sources for which EPA has established D/F limits such as cement plants and waste-to-energy (WTE) facilities. The present limits applicable to new cement plants (depending on operating mode) are 0.2 and 0.4 nanograms toxic equivalent (TEQ) per dry standard cubic meter (ng/dscm) at 7% O_2. The value applicable to new WTE units is 13 ng/dscm @7% O_2.

A reasonable action level would be 13 ng/dscm or 0.20 TEQ ng/dscm whichever is less stringent. Beyond those levels, the applicant would need to consider activated carbon injection in the baghouse or other actions such as temperature management and residence time options.

6. STARTUPS OF THE GASIFIER AND CHAR COMBUSTOR

The applicant submitted information regarding the sequence of events and emissions that occur during the startups, planned shutdowns or emergency shutdowns of key facility components such as the gasifier and char combustor. Following is a summary of the procedures submitted by BG&E.

6.1. Gasifier Startups and Shutdowns

The initial startup of the gasifier will utilize a blower to force air into the gasifier. One hour later, a 25MMBtu/hr natural gas fire burner will be started. The burner will fire for approximately 12 hours. During this time, the sand bed will be heated to the operating temperature of approximately 1,600 °F and will beginning fluidizing. At this point the burner will be turned off and woody biomass and steam will begin to be fed into the gasifier. After one hour, the woody biomass feed rate will be gradually increased to the maximum of approximately 30.4 tons per hour. This ramp up of the fed rate will take roughly one hour. Also during this time, the gasifier blower will be turned off and over the next hour the gasifier should reach steady state conditions.

Routine shutdowns of the gasifier are planned in advance and follow an orderly process. The general process is as follows:

- Prepare the gasifier for shutdown by reducing the woody biomass feed rate to 50 percent of the design rate;
- Start the gasifier air blower and open the bypass;
- Stop the biomass fed, monitor BPG flowrate and the CO and CO2 composition of the BPG;
- Gradually increase blower airflow into the gasifier using CO and CO2 levels to determine when woody biomass (carbon) burned out has occurred;
- Gradually reduce steam flow to zero;
- Maintain adequate upward flow during the transition from steam to air flow; and,
- Stop airflow into the gasifier once carbon burnout has occurred.

6.2. Combustor Startups and Shutdowns

The startup of the combustor follows the same general procedures and timelines as the gasifier. However, instead of woody biomass, char from the gasifier and tars from the OLGA gas cleanup system are feed to the combustor toward the end of the startup process. Also, instead of steam, air flows into the combustor during steady state operation.

The combustor has no specific shutdown sequence. Airflow is maintained at the design rate to maintain bed fluidization and allow the burnout of char and tars. The combustor blower is turned off at the same time as the gasifier blower.

7. AMBIENT AIR QUALITY

7.1. Introduction

The proposed project will not increase emissions at levels in excess of PSD significant amounts. Therefore, an ambient air quality modeling analysis was not required for this project. The following sections include a review of current air quality in the vicinity of the project, along with information regarding this project and how it relates to other nearby sources of pollution.

7.2. Major Stationary Sources in Leon, Wakulla, Jefferson and Taylor Counties

The current largest stationary sources of air pollution in Leon, Wakulla, Jefferson and Taylor Counties are listed below. The information is from annual operating reports submitted to the Department from 2007.

Table 8. Largest Sources of SO_2 in Leon, Wakulla, Jefferson and Taylor Counties.

Owner	Site Name	Tons per year
Buckeye	Buckeye	2,653
City of Tallahassee	Arvah B. Hopkins Generating Station	498
St Marks Powder, Inc.	St Marks Powder, Inc.	134
Biomass Gas & Electric	**Tallahassee Renewable Energy (Proposed)**	**83**
C.W. Roberts Contracting	Tallahassee Asphalt Plant	7

Table 9. Largest Sources of PM/PM_{10} in Leon, Wakulla, Jefferson and Taylor Counties.

Owner	Site Name	Tons per year
Buckeye	Buckeye	843
Biomass Gas & Electric	**Tallahassee Renewable Energy (Proposed)**	**114**
Gilman Building Products	Gilman Building Products	88
St Marks Powder, Inc.	St Marks Powder, Inc.	47
City of Tallahassee	Purdom Generating Station	38
SI Group-Energy, LLC	Monticello Plant	33
City of Tallahassee	Arvah B. Hopkins Generating Station	31

Table 10. Largest Sources of CO in Leon, Wakulla, Jefferson and Taylor Counties.

Owner	Site Name	Tons per year
Buckeye	Buckeye	5,948
City of Tallahassee	Arvah B. Hopkins Generating Station	335
Biomass Gas & Electric	**Tallahassee Renewable Energy (Proposed)**	**204**
SI Group-Energy, LLC	Monticello Plant	143
City of Tallahassee	Purdom Generating Station	102
Leon County	Solid Waste Management Facility	60
C.W. Roberts Contracting	Tallahassee Asphalt Plant	16

Table 11. Largest Sources of VOC in Leon, Wakulla, Jefferson and Taylor Counties.

Owner	Site Name	Tons per year
Buckeye	Buckeye	655
St Marks Powder, Inc.	St Marks Powder, Inc.	415
Gilman Building Products	Gilman Building Products	157
FL Gas Transmission Co.	Perry Compressor Station 15	37
City of Tallahassee	Arvah B. Hopkins Generating Station	20
Leon County	Solid Waste Management Facility	20
Biomass Gas & Electric	**Tallahassee Renewable Energy (Proposed)**	**18**
Defiance, Inc.	Precision Engine Products	14

Table 12. Largest Sources of NO_X in Leon, Wakulla, Jefferson and Taylor Counties.

Owner	Site Name	Tons per year
Buckeye	Buckeye	1,576
City of Tallahassee	Arvah B. Hopkins Generating Station	726
FL Gas Transmission Co.	Perry Compressor Station 15	581
City of Tallahassee	Purdom Generating Station	219
Biomass Gas & Electric	**Tallahassee Renewable Energy (Proposed)**	**197**
SI Group-Energy, LLC	Monticello Plant	106

7.3. Air Quality and Monitoring in the Leon and Wakulla Counties

The Tallahassee Ambient Monitoring Section (AMS) operates seven monitors at four sites measuring $PM_{2.5}$ and ozone (O_3). The 2007 monitoring network is shown in the figure below.

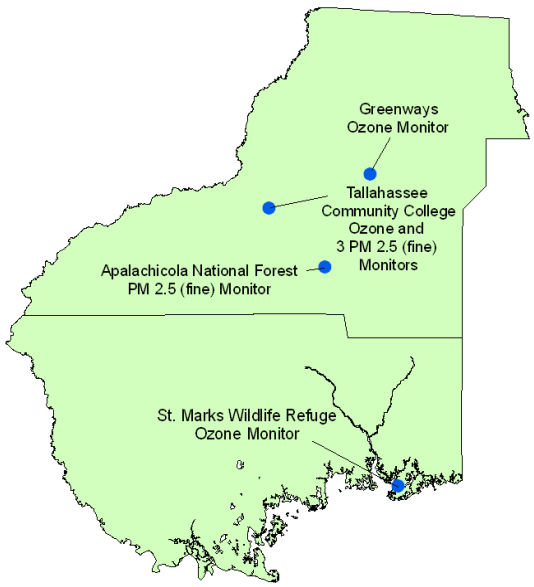

Figure 17. Tallahassee AMS Monitoring Network.

Table 13. Ambient Air Quality Nearest to Project Site (2007).

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
$PM_{2.5}$	Tallahassee Community College	24-hour	81*	49			$\mu g/m^3$
		Annual			12	15 [c]	$\mu g/m^3$
		98th Percentile	31.5 (3 years)			35 [b]	$\mu g/m^3$
Ozone	Tallahassee Community College	1-hour	0.084	0.084		0.12 [a]	ppm
		8-hour	0.075	0.073		0.075 [d]	ppm
		8-hour	2007 3-yr attainment		0.070	0.075 [d]	ppm

a. Not to be exceeded on more than an average of one day per year over a three-year period
b. Three year average of the 98th percentile of 24-hour concentrations
c. Three year average of the weighted annual mean
d. Three year average of the 4th highest daily max

* Some data may be excluded to due fires, resulting in lower concentrations. EPA is in the process of reviewing the data.

All monitors nearest to the project site show attainment with the National Ambient Air Quality Standards.

$PM_{2.5}$ or PM fine is primarily influenced by man-made and natural precursors in the atmosphere on a regional basis rather than locally. Regionally, man-made precursors of PM fine are orders of magnitude higher than what would be found locally. The following figure shows how the Tallahassee Community College PM fine monitor was affected by a regional high sulfate event.

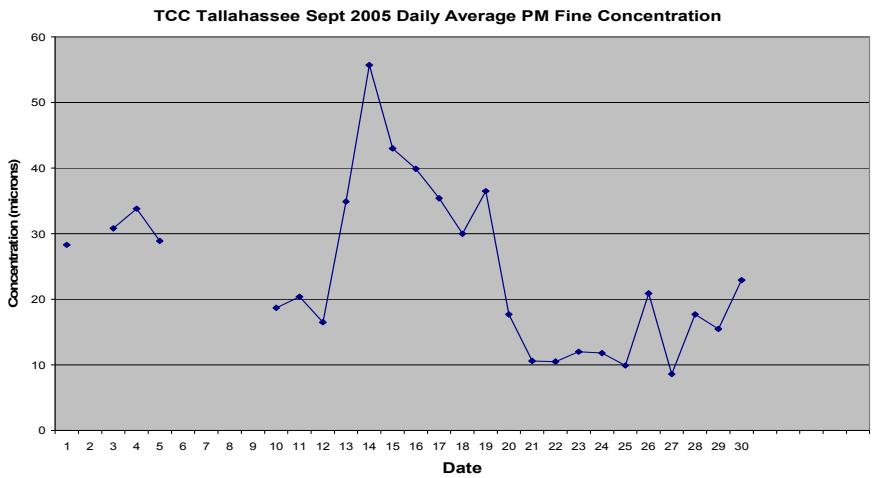

Figure 18. Tallahassee Community College PM fine monitor September 2005.

The regional nature of the event can be appreciated based on the following map. The zones of high concentration encompassed a large portion of the Florida Panhandle and the Big Bend area, including Tallahassee.

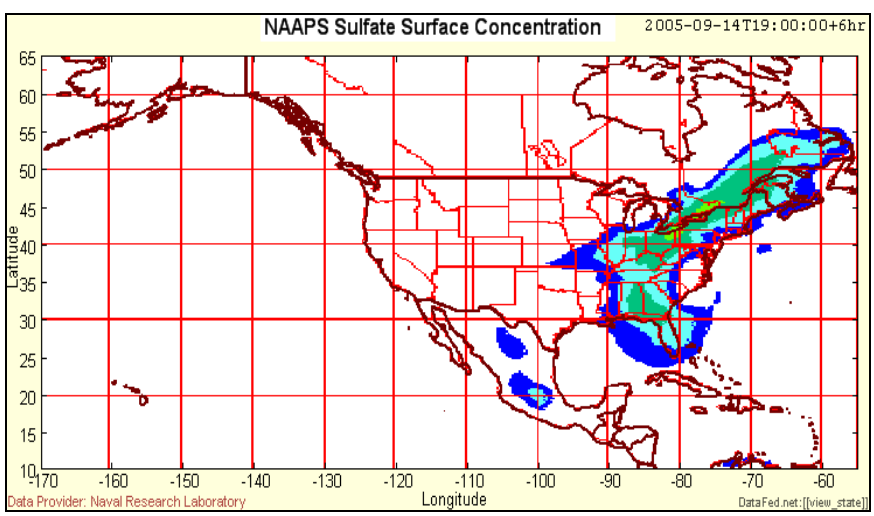

Figure 19. Sulfate Event from September 2005

In comparison, the sulfate concentrations were much lower in Leon County on October 23, 2008, as shown in Figure 24. Although, there are other factors that can influence fine particle pollution, the monitor at Tallahassee Community College on the same day in October had concentrations much less than what was seen in the example noted above.

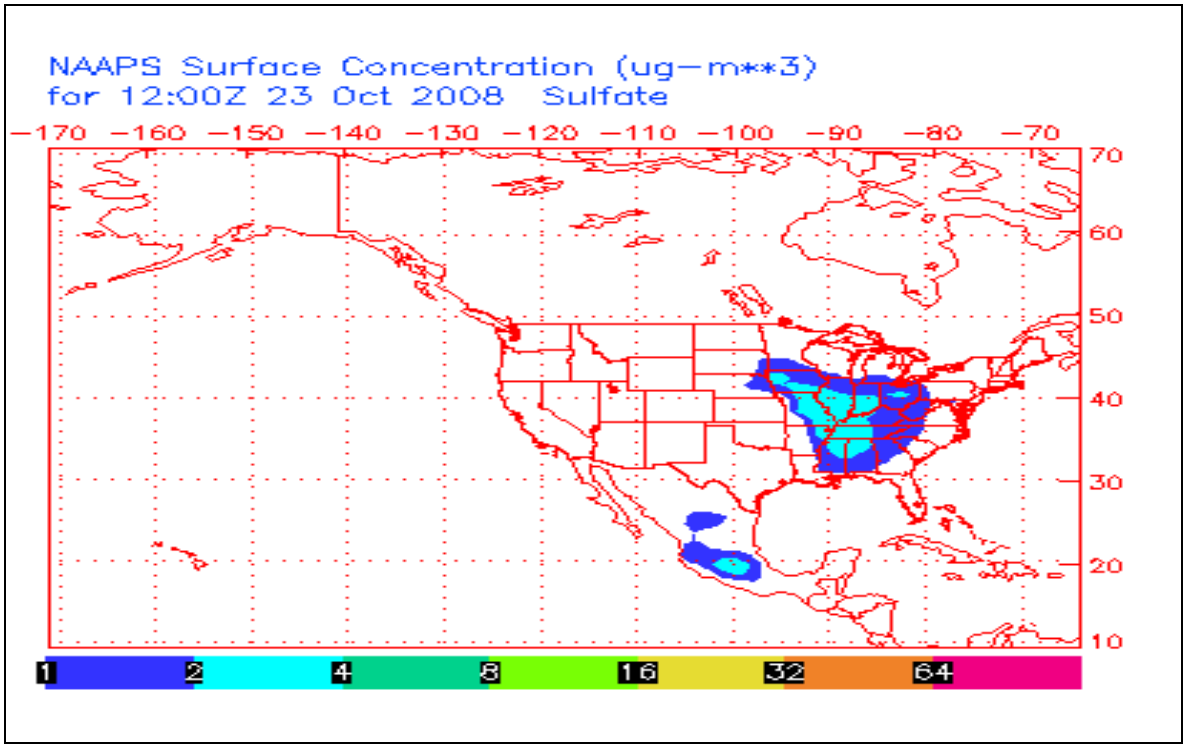

Figure 20. Sulfate Concentrations from October 2008.

Emissions from the proposed project are less than the significant emissions rates (SER) for each PSD-pollutant. Based on the fact that the project does not trigger PSD, the present ambient air monitoring concentrations and the regional nature of pollution events affecting the area, the Department concludes that this project will not cause or contribute to a violation of a National Ambient Air Quality Standard.

Conclusion

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution control regulations as conditioned by the Draft Permit. This determination is based on a technical review of the application, reasonable assurances provided by the applicant and the conditions specified in the draft permit and does not serve as precedent for any other projects. Alvaro Linero is the project engineer that reviewed this application.

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[8] Letter. Richani, B., General Electric to Gnecco, J., FP&L. Expected Particulate Matter Emissions: GE 7FA DLN Combustion Turbines. September 19, 2003.