Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

October 24, 2008

Electronically Sent – Received Receipt Requested.

glenn@biggreenenergy.com
Mr. Glenn Farris, President and CEO
Biomass Gas and Electric of Tallahassee, LLC
3500 Parkway Lane, Suite 440
Atlanta, Georgia 30092

Re: DEP File No. 0730109-001-AC
Tallahassee Renewable Energy Center
Biomass Integrated Gasification and Combined Cycle Unit

Dear Mr. Farris:

On April 3, 2008, you submitted an application for an air construction permit to construct a biomass-fed integrated gasification and combined cycle unit (BIGCC) at the facility identified above. Enclosed are the following documents:

- Written Notice of Intent to Issue Draft Air Construction Permit;
- Public Notice of Intent to Issue Draft Air Construction Permit;
- Technical Evaluation and Preliminary Determination; and
- Draft Air Construction Permit.

The Public Notice of Intent to Issue Draft Air Construction Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact A. A. Linero, Program Administrator at (850) 921-9523.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/aal

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE DRAFT AIR CONSTRUCTION PERMIT

In the Matter of an
Application for Air Construction Permit by:

Mr. Glenn Farris, President and CEO
Biomass Gas and Electric of Tallahassee, LLC
3500 Parkway Lane, Suite 440
Atlanta, Georgia 30092

DEP File No. 0730109-001-AC
Tallahassee Renewable Energy Center
Biomass Integrated Gasification Combined Cycle Unit
Leon County, Florida

Facility Location: The proposed Tallahassee Renewable Energy Center (TREC) will be located in Leon County near South Lipona and Roberts Road in Tallahassee.

Project: On April 3, 2008, Biomass Gas and Electric, LLC submitted an air permit application to construct the TREC consisting of a nominal 42 megawatts (net) biomass integrated gasification and combined cycle unit and ancillary equipment. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from permitting requirements and an air construction permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, Mail Station (MS) 5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. In addition, electronic copies of key documents are available at the following web link:

www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm.

Notice of Intent to Issue Air Construction Permit: The Permitting Authority gives notice of its intent to issue an air construction permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 14-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, MS 35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Construction Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this Written Notice of Intent to Issue Air Construction Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Construction Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Construction Permit package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Air Construction Permit) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested or by U.S. certified mail as indicated below before the close of business on 10/27/08 to the persons listed below.

Glenn Farris, BG&E: glenn@biggreenenergy.com
Dick Fancher, DEP NWD: dick.fancher@dep.state.fl.us
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Kathy Forney, EPA Region 4: forney.kathleen@epamail.epa.gov
Heather Abrams, EPA Region 4: Abrams.Heather@epa.gov
Jane Sauls, Chair, Leon County Board of County Commissioners: saulsj@leoncountyfl.gov
Bill Proctor, Commissioner, Leon County: proctorb@leoncountyfl.gov
John Marks, Mayor, City of Tallahassee: john.marks@talgov.com
Anita Favors Thompson, Manager, City of Tallahassee: anita.favors.thompson@talgov.com
Vickie Gibson, DEP BAR: Victoria.Gibson@dep.state.fl.us (for read file)
John Gibby, Citizen: gibbyj@earthlink.net
Joy Towles Ezell, Citizen: hopeforcleanwater@yahoo.com
Deb Swim, Citizen: daswim@gmail.com
Joe Cain, Citizen: joecain1@comcast.net
Dr. Ronald Saff, Floridians Against Incinerators in Disguise: ronsaff@aol.com
Vincent Salters, Professor of Geology, FSU: salters@magnet.fsu.edu
Dr. Scott Hannahs, Director of DC Field Instrumentation & Operations, FSU: sth@magnet.fsu.edu
Dr. Heinz Luebkemann, Retired Professor, FSU: hluebkemann@comcast.net
Shereitte C. Stokes IV, Environmental Science Institute, FAMU: shereitte@gmail.com
Richard Gragg, Environmental Science Institute, FAMU: richard.gragg@famu.edu
Richard Gragg III: richardgraggiii@mac.com
Bob Fulford, Citizen: bobfulford@nettally.com
Anita L. Davis, FCAN & JGNA: anitald@embarqmail.com
Susie Caplowe, Florida League of Conservation Voters: susiecaplowe@comcast.net
Dave Ciplet: Global Alliance for Incinerator Alternatives: dave@no-burn.org
Bradley Angel: bradley@greenaction.org
Neil Seldman, Institute for Self-Reliance: nseldman@ilsr.org
Donald L. Mellman, Vice-President, Physicians for Social Responsibility: dmellman@post.harvard.edu
Lynn Ringenberg, President, Physicians for Social Responsibility: ring@tampabay.rr.com
Dr. Andres Rodriguez, Capital Medical Society: by U.S. Mail

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 10/27/08 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE DRAFT AIR CONSTRUCTION PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
DEP File No. 0730109-001-AC
Biomass Gas and Electric of Tallahassee, LLC
Tallahassee Renewable Energy Center
Biomass Integrated Gasification Combined Cycle Unit
Leon County

Applicant: The applicant for this project is Biomass Gas and Electric of Tallahassee, LLC (BG&E). The applicant's authorized representative and mailing address is: Mr. Glenn Farris, President and Chief Executive Officer, BG&E, 3500 Parkway Lane, Suite 440, Atlanta, Georgia 30092.

Facility Location: The proposed Tallahassee Renewable Energy Center (TREC) will be located in Leon County on a 21.2 acre site 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.

Project: On April 3, 2008, BG&E submitted an air permit application to construct the TREC consisting of a nominal 42 megawatts (MWnet) biomass integrated gasification combined cycle unit and ancillary equipment. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

Municipal solid waste (MSW) is expressly prohibited as a fuel source for the facility. The fuel source for the facility will be exclusively woody biomass that consists primarily of wood chips but may also include agricultural crops and byproducts, logging and lumber mill residues, untreated wood materials, and other non-fossil organic materials. The material will be dried and fed into a vessel containing a heated bed of circulating olivine (sand) where the woody biomass will be converted to biomass product gas (BPG).

BG&E's estimates of emissions in tons per year (TPY) from the proposed TREC project are summarized in the following table. The permitted emissions representing theoretical potential to emit are also included.

Pollutants	Estimated Emissions (TPY)	Potential Emissions (TPY)
Carbon Monoxide (CO)	204	231
Nitrogen Oxides (NO_X)	197	214
Particulate Matter (PM/PM_{10})	114/114	156/156
Sulfur Dioxide (SO_2)	83	83
Volatile Organic Compounds (VOC)	18	18
Hazardous Air Pollutants (HAP)	<5	<5

The BPG will be cleaned, compressed and used as fuel in two nominal 14.8 MW (gross) combustion turbine-electrical generators (CT). Heat from the CT exhaust gas will be recovered in two heat recovery steam generators (HRSG) equipped with BPG-fueled duct burners. The resulting steam will drive a single nominal 20.7 MW (gross) steam turbine-electrical generator (STG). NO_X emissions (concentrations) from BPG combustion in the CT and DB will be limited to achieve 32.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2). CO concentrations will be limited to 50.0 ppmvd @15% O_2. Emissions of PM/PM_{10}, SAM, SO_2, and VOC will be controlled to very low levels by good combustion and the cleanup of the BPG prior to combustion. Ammonia emissions (NH_3)

generated due to NO_X control will be limited to 10 ppmvd. The draft permit includes a dioxin/furan design standard of 0.15 toxic equivalent (TEQ) nanograms per dry standard cubic meters at @7% O_2.

The BPG cleanup system includes: particulate removal; tar removal; and scrubbing to remove other impurities such as ammonia (NH_3), hydrogen chloride (HCl), hydrogen sulfide (H_2S) and alkali metals. The CT exhaust gas cleanup consists of a selective catalytic reduction (SCR) system for NO_X. The Department also requires continuous emissions monitoring systems (CEMS) for NO_X and CO and fuel analysis for sulfur to limit SO_2 and sulfuric acid mist (SAM) emissions.

Char removed from the BPG and tar from the BPG cleanup system will be combusted in a separate vessel to provide additional heat to the gasification process. The resulting char combustion exhaust gas will pass through two cyclones and then be filtered in a baghouse and exhausted to the atmosphere. A continuous opacity monitor will be required and also a process monitor for CO. It will be periodically tested for emissions of PM/PM_{10}, NO_X and dioxin/furan.

There will be an exhaust stack for the char combustor, two exhaust stacks for the CT/HRSG trains, cooling towers, two flares, a natural gas-fueled auxiliary boiler and natural gas-fueled startup burners for the gasifier and char combustor.

This project did not trigger the rules for the prevention of significant deterioration (PSD) regulations. Therefore, air quality impact modeling was not required. The Department reviewed ambient air monitoring records and has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from permitting requirements and an air construction permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, Mail Station (MS) 5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft air construction permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. In addition, electronic copies of key documents are available at the following web link:

www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm .

Notice of Intent to Issue Air Construction Permit: The Permitting Authority gives notice of its intent to issue an air construction permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a final air construction permit in accordance with the conditions of the proposed draft air construction permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed draft air construction permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 14-day period. If written comments received result in a significant change to the draft air construction permit, the Permitting Authority shall revise the draft air construction permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within 14 days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication.

A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

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

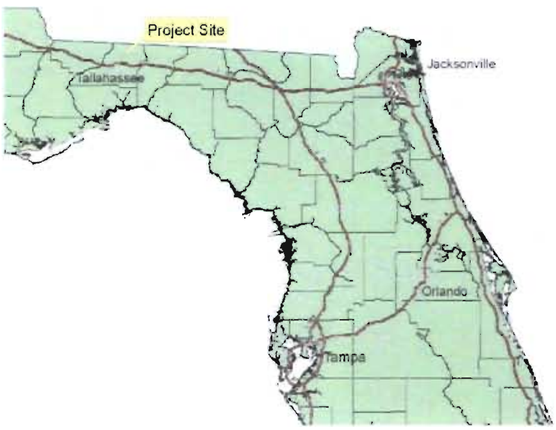
***Authorized Representative*:** Mr. Glenn Farris, President and CEO

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.



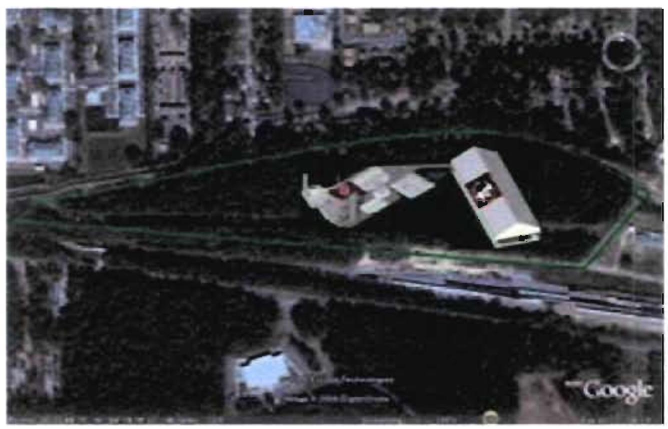


Figure 1. Project Location in Tallahassee and Rendition of Future TREC Project Site.

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.

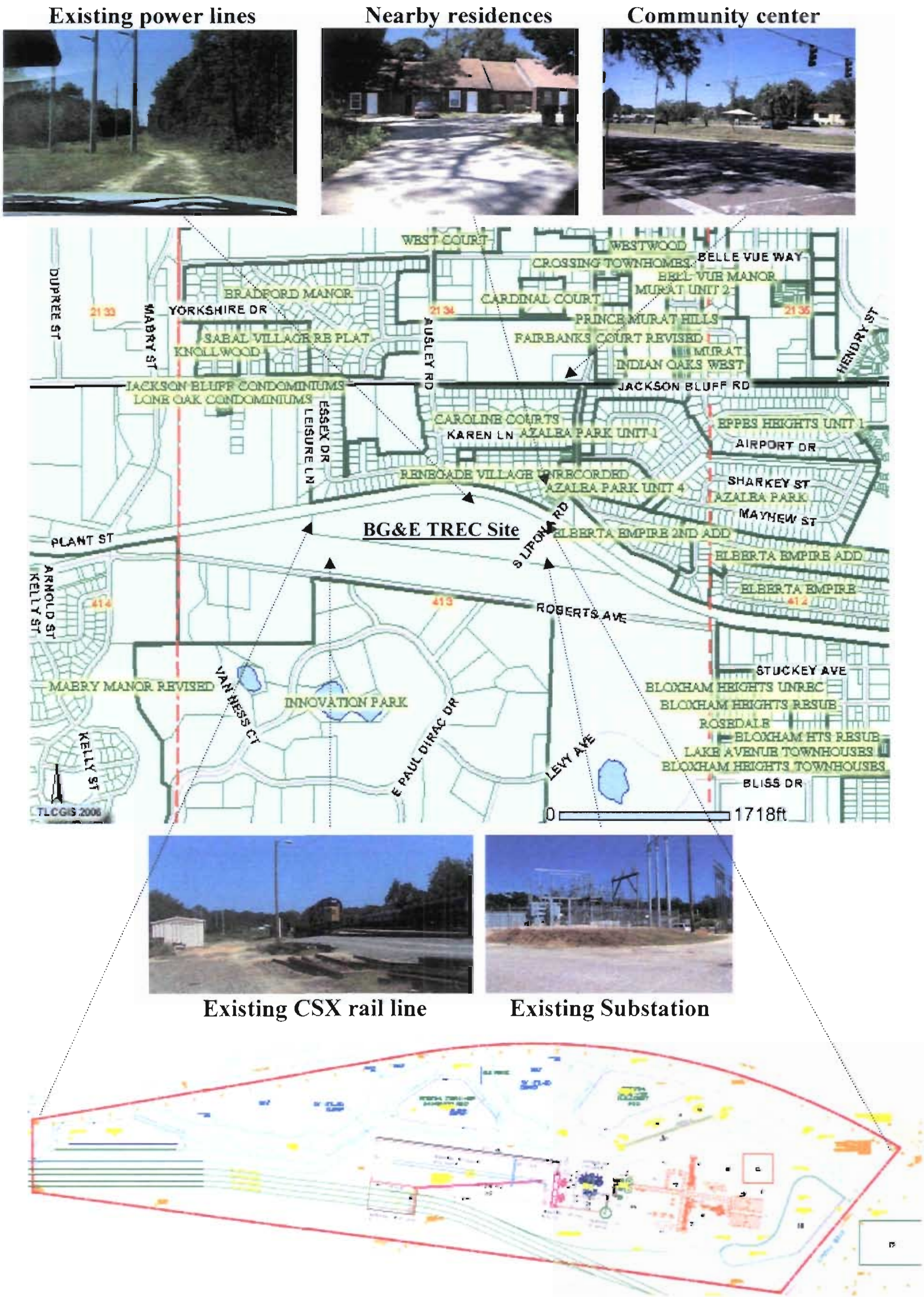


Figure 2. BG&E site layout of TREC. Insert into Tallahassee Leon County map above.

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.

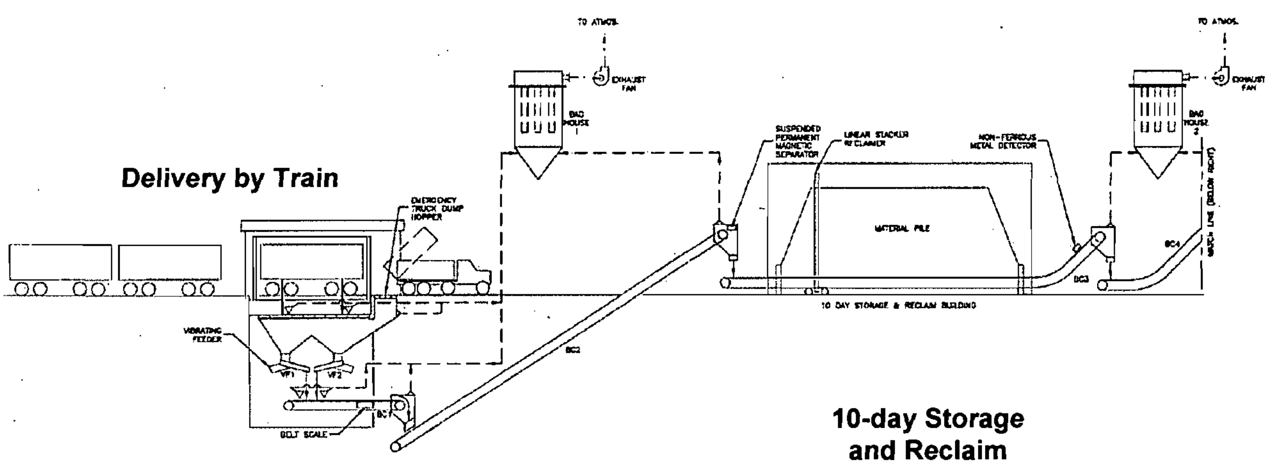


Figure 3. Woody biomass receiving, storage, and conveyance to dryer.

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.

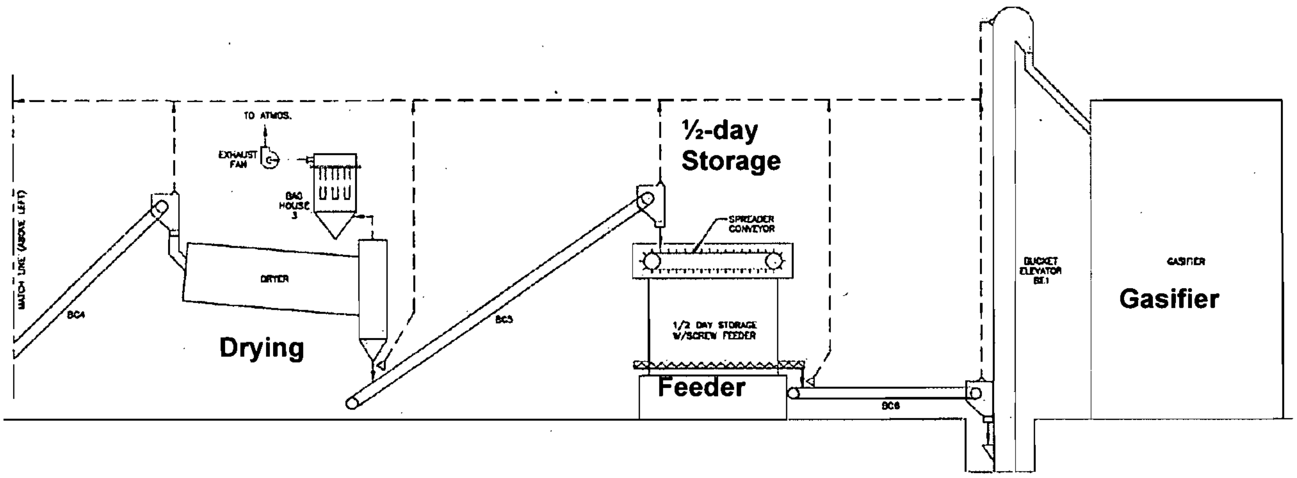


Figure 4. Woody biomass drying, conveyance and feeding to gasifier.

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.

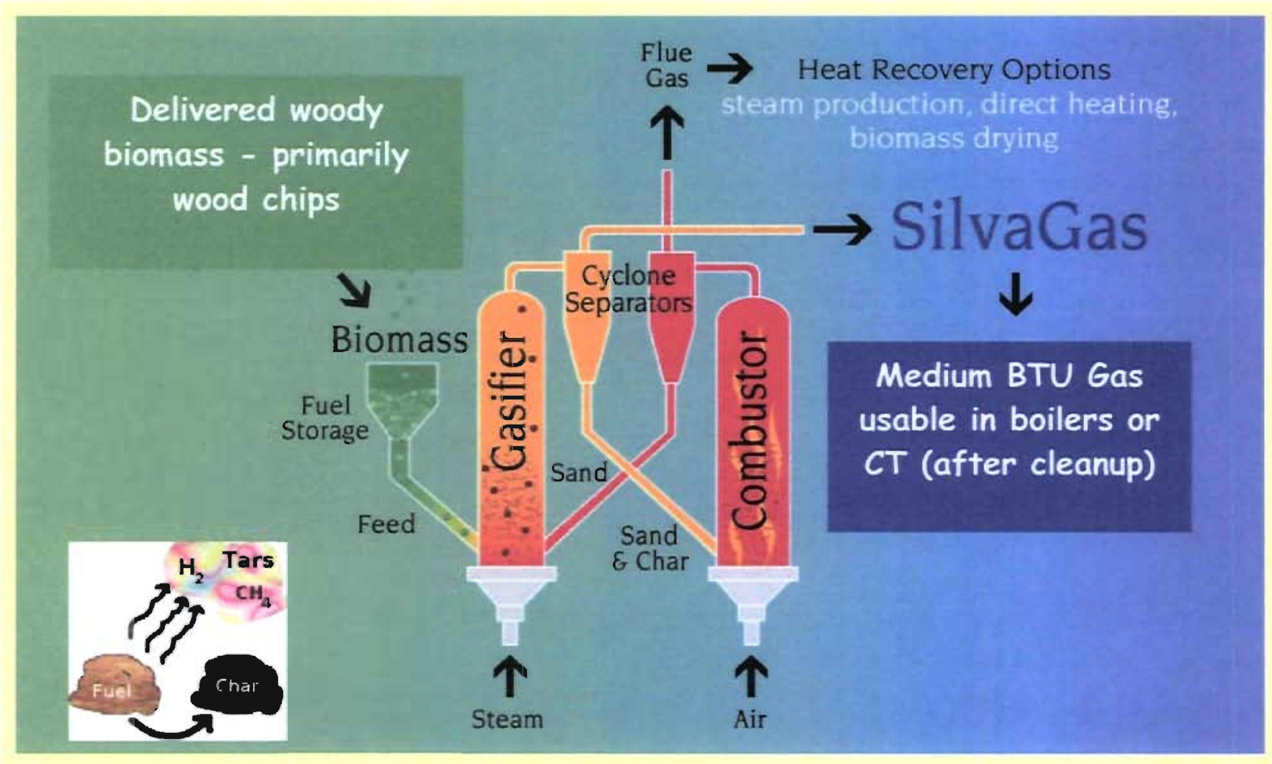


Figure 5. Gasifier/Combustor Section of the SilvaGas Process and Exhaust streams.

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 decomposition 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*→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.

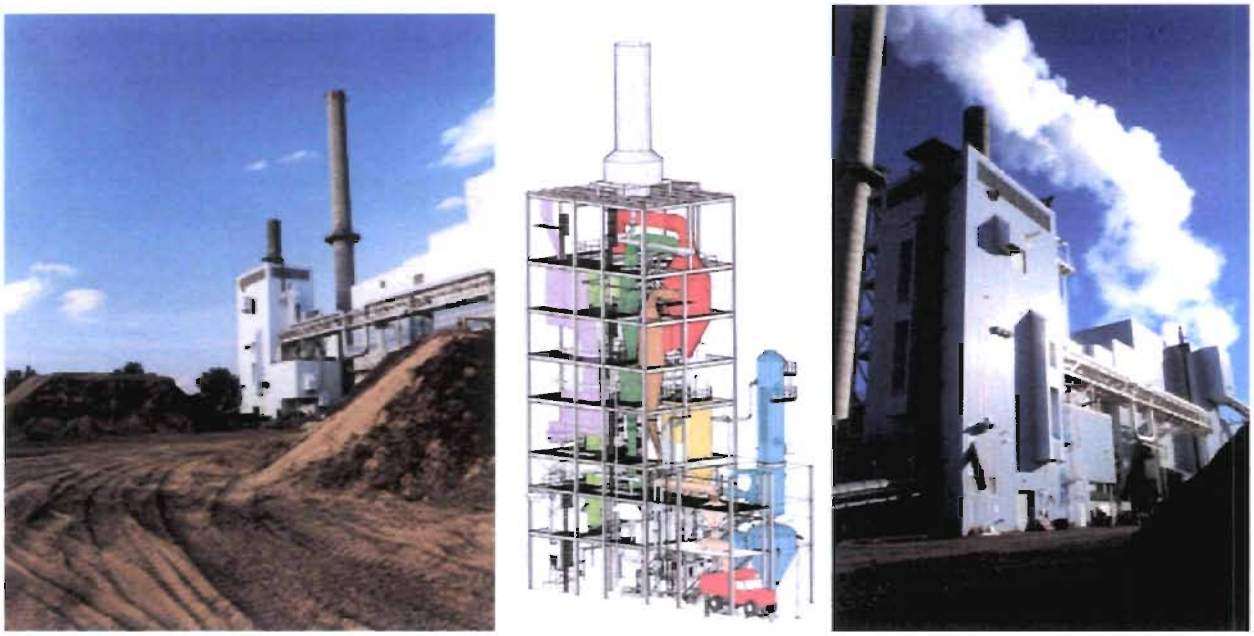


Figure 6. External Views and Internal Diagram of Gasifier/Combustor at McNeil Station.

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.

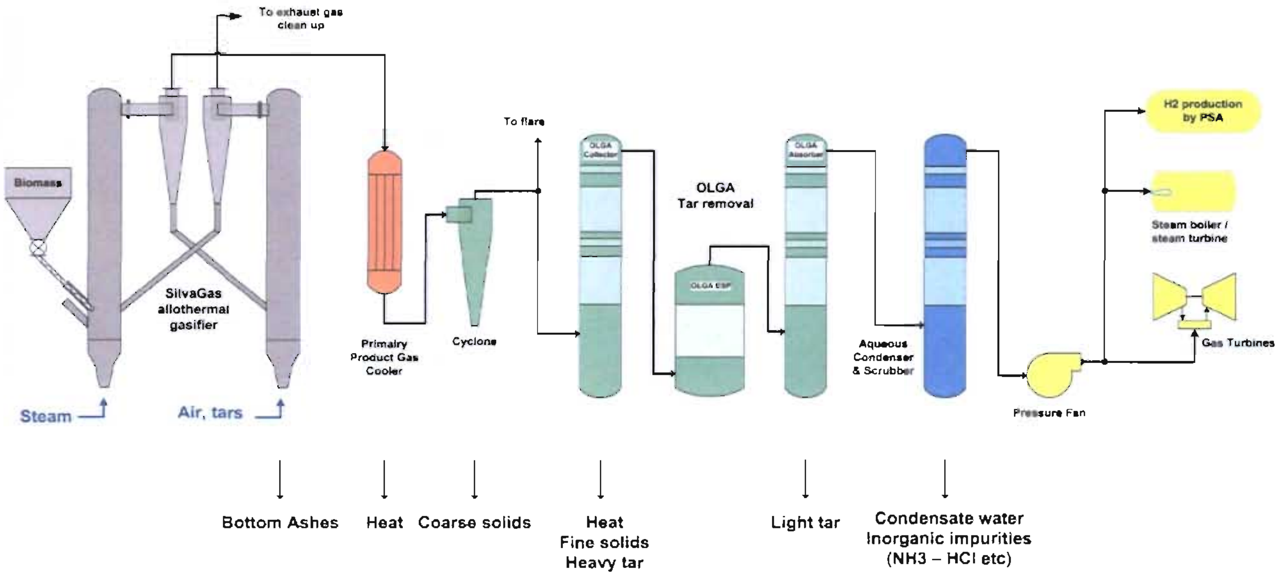


Figure 7. SilvaGas Gasifier/Combustor, BGP Cleanup System and Power Generation.

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.

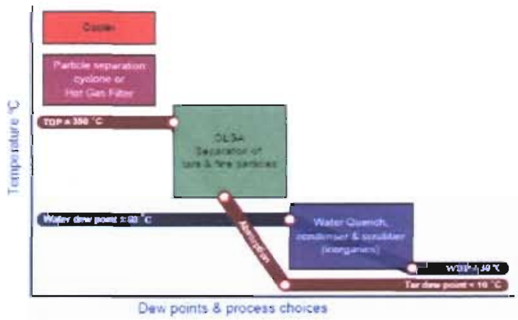
The presence of tars in the BPG is one of the biggest challenges to commercial application of BIGCC. The tars formed in the gasifier comprises a wide spectrum of straight, branched or ringed organic compounds that can be simply characterized as "heavy tars" and "light tars".

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.



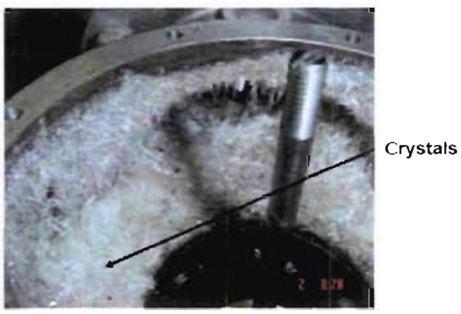


Figure 8. Function of OLGA. Wood pyrolysis tar. Naphthalene pluggage of valves.

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.

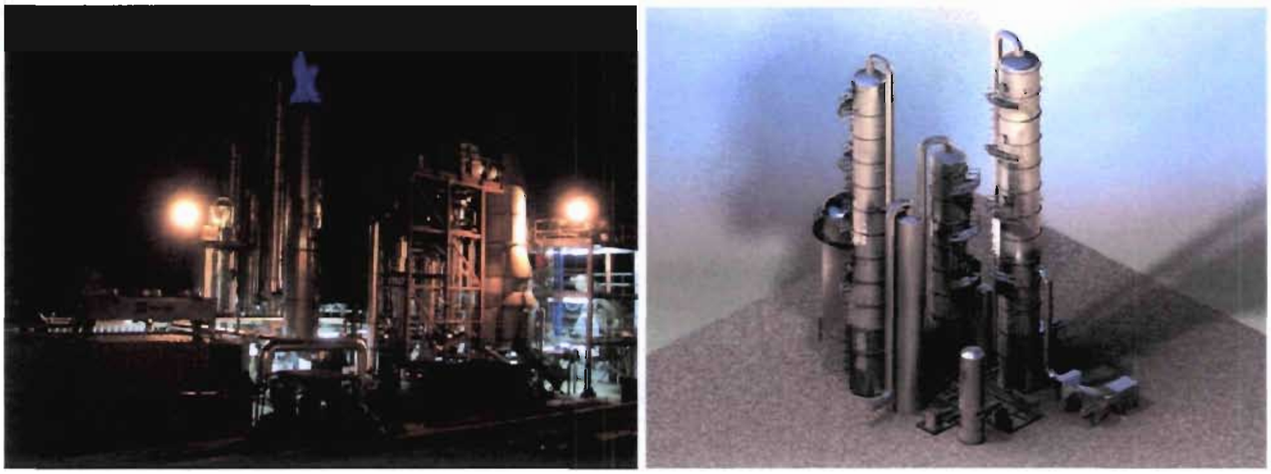


Figure 9. OLGA demonstration in Moisannes, France. Physical model of OLGA.

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.

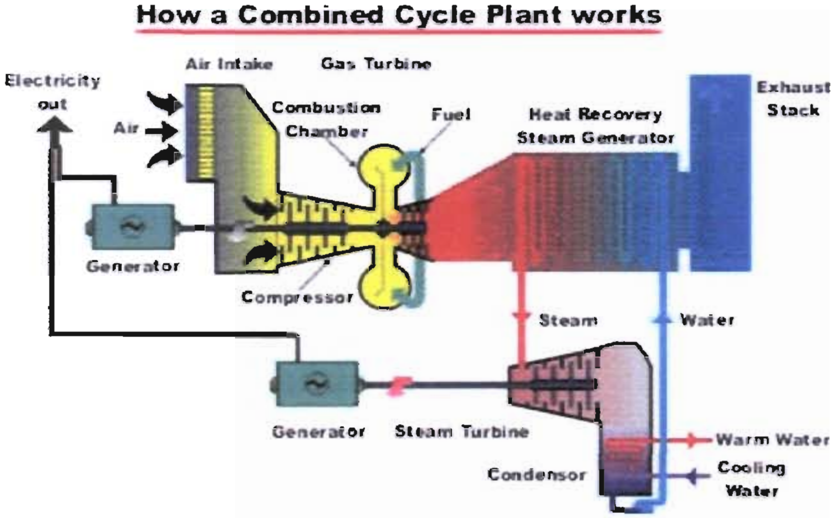


Figure 11. A conventional natural gas fueled combined cycle unit.

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.

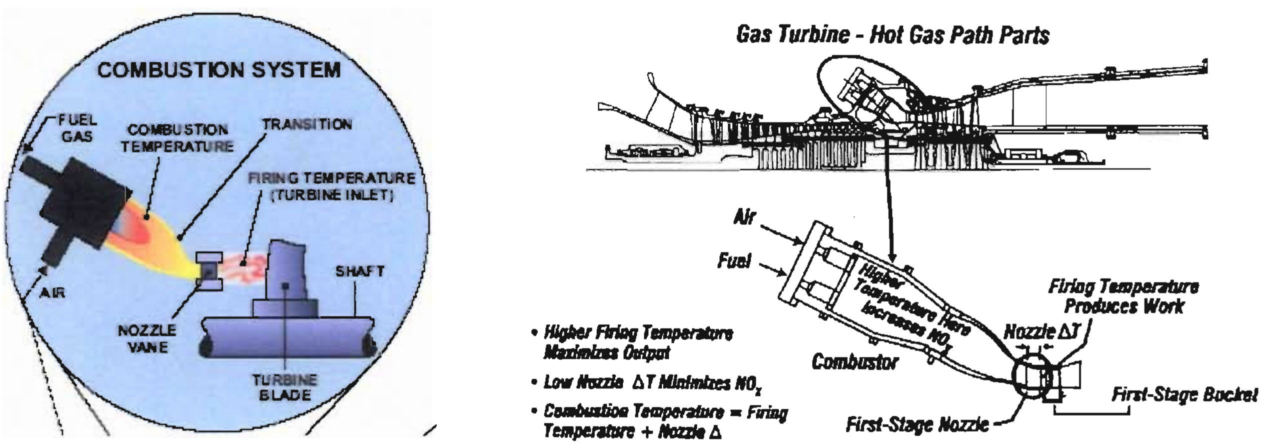


Figure 12. Relation between Combustion and Firing Temperatures and NO_X Formation.

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.

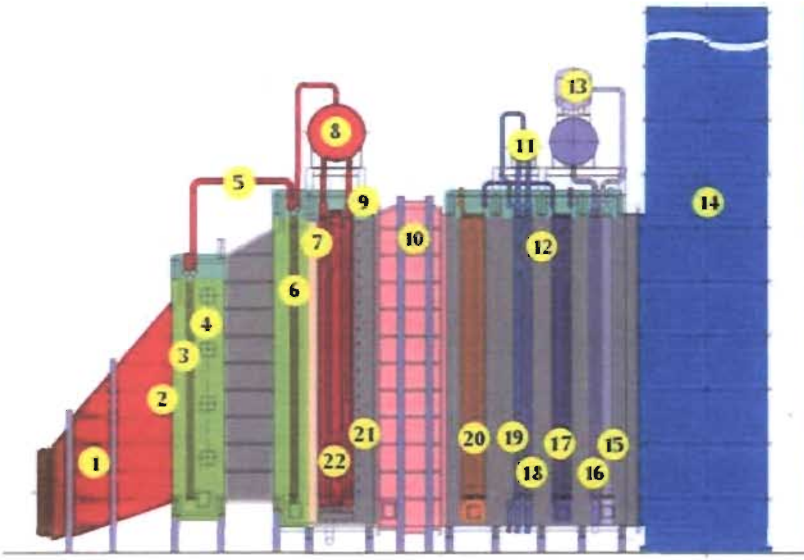


Figure 13 – Key HRSG Components (10 is SCR).

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:

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

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 <u>or</u> 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.

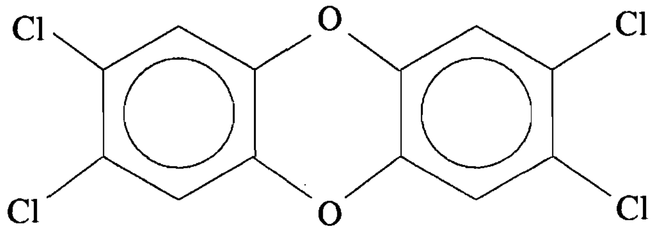


Figure 15 – Skeletal diagram of the 2,3,7,8 TCDD molecule.

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:

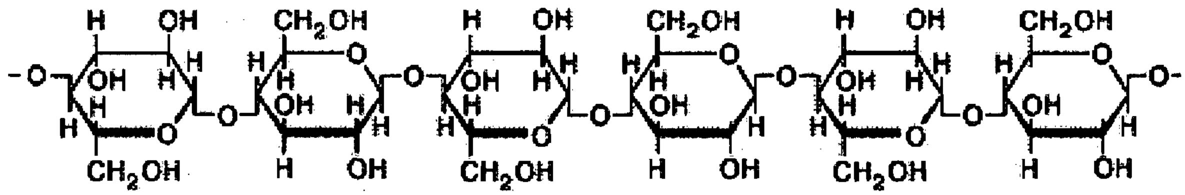


Figure 16 – Skeletal diagram of cellulose.

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.

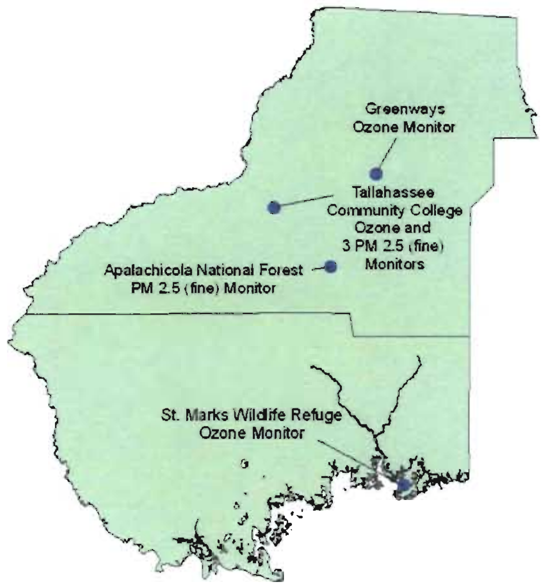


Figure 17. Tallahassee AMS Monitoring Network.

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.

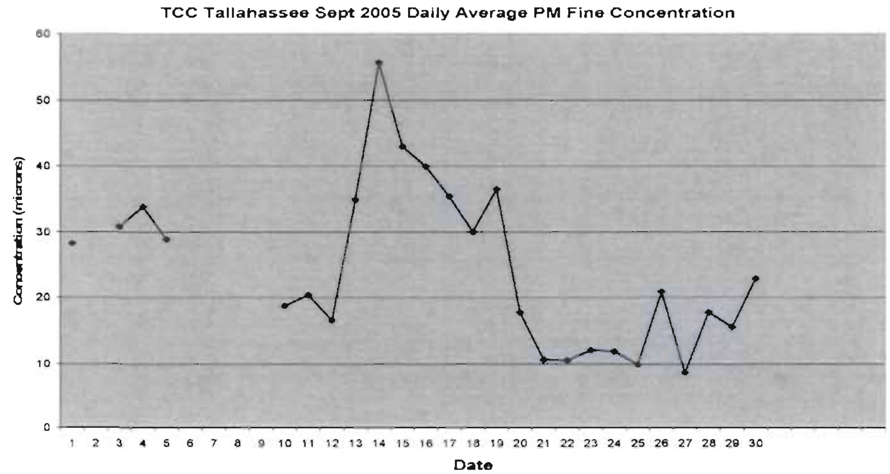


Figure 18. Tallahassee Community College PM fine monitor September 2005.

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.

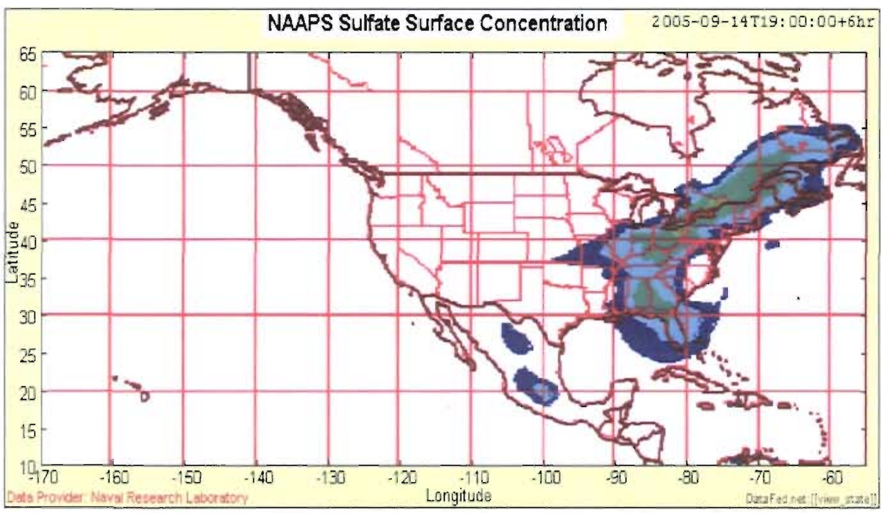


Figure 19. Sulfate Event from September 2005

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.

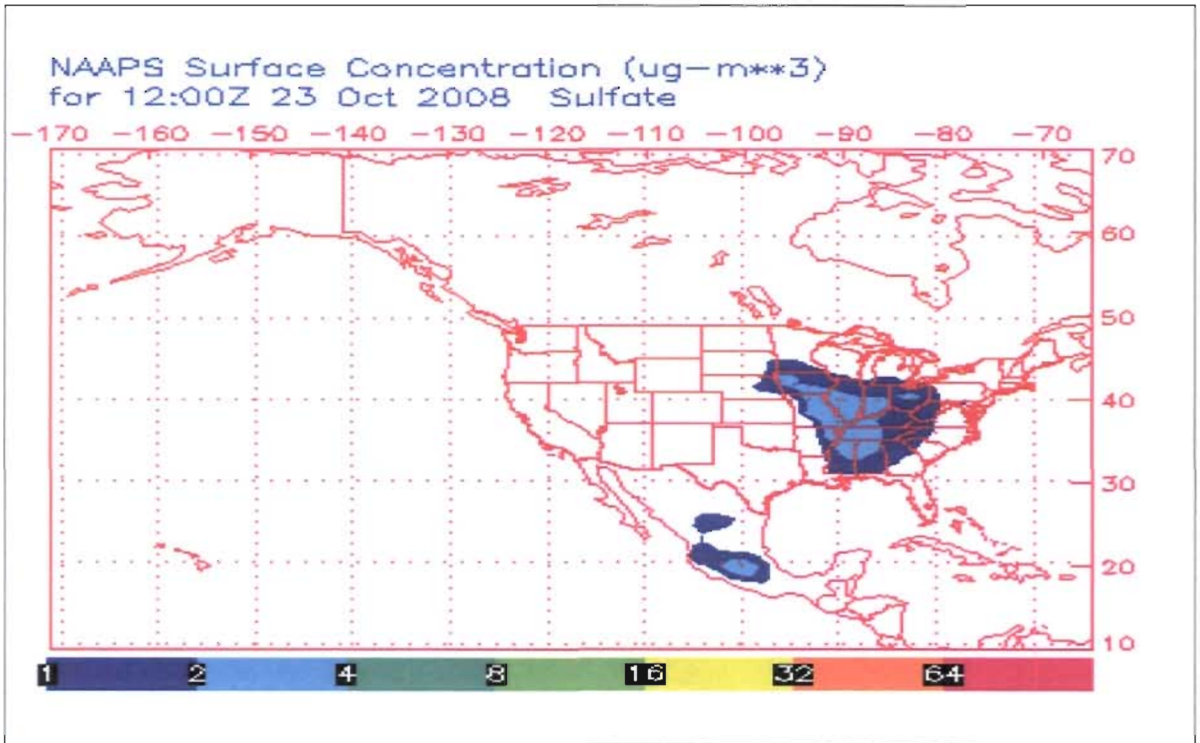


Figure 20. Sulfate Concentrations from October 2008.

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.

REFERENCES

1 Article. Farina, G.L. and Bressan, L. "Optimizing IGCC Design." Foster Wheeler Review. 1999.

2 Paper. Gangwal, S. et. al. Research Triangle Institute, SRI, GE. "Catalytic Ammonia Decomposition for Coal-Derived Fuel Gases." DOE Advanced Coal-Fired Power Systems 1996 Review Meeting. Morgantown, West Virginia. July 16-18, 1996.

3 Paper. Paisley, et al. FERCO, NREL, BED, Batelle. The Biomass Gasification Process by Batelle/FERCO: Design, Engineering, Construction and Startup. Gasification Technologies Council Annual Conference. 1998.

4 Paper. Paisley, et al. FERCO, NREL, BED. "Preliminary Operating Results from the Batelle/FERCO Gasification Demonstration Plant in Burlington, Vermont, U.S.A." The 1st World Conference and Technology Exhibition on Biomass for Energy and Industry. Seville. June 2000.

5 Report. Boerrigter, H. et. al. ERCN, Dahlman. "OLGA Tar Removal TechnologyProof-of-Concept for application in integrated biomass gasification combined heat and power systems." 2005.

6 Paper. Könemann, H.W.J. and van Paasen, S.V.B. ERCN, Dahlman. "OLGA Tar Removal Technology4 MW Commercial Demonstration." Berlin. November, 2007.

7 Letter. Richani, B., General Electric to Gnecco, J., FP&L. Particulate Matter Emissions: GE 7241FA DLN Combustion Turbines. June 17, 2003.

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

DRAFT PERMIT

PERMITTEE

Biomass Gas and Electric of Tallahassee, L.L.C.
3500 Parkway Lane, Suite 4000
Atlanta, Georgia 30092

Authorized Representative: Mr. Glenn Farris
President and Chief Executive Officer

Air Permit No. 0730109-001-AC
Tallahassee Renewable Energy Center
Biomass-fed Integrated Gasification Combined Cycle
Permit Expires: December 31, 2011
Initial Construction
Leon County

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 42 megawatts (MWnet) biomass-fed integrated gasification and combined cycle power plant called the Tallahassee Renewable Energy Center. The facility will be located in Leon County along Lipona Road at Roberts Avenue in Tallahassee, Florida. The UTM coordinates are Zone 16, 757.34 km East, and 3369.8 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C.

CONTENTS

Executed in Tallahassee, Florida

(DRAFT)

Joseph Kahn, Director
Division of Air Resource Management

(Date)

FACILITY AND PROJECT DESCRIPTION

The proposed facility is a nominal 42 MWnet biomass-fed integrated gasification combined cycle (BIGCC) power plant called the Tallahassee Renewable Energy Center (TREC). The BIGCC unit will consist of:

- A biomass receiving, handling, storage and drying system;
- A biomass gasification system that yields biomass product gas (BPG) and char;
- A char combustor with sand and ash removal cyclones and a fabric filter baghouse;
- A BPG cleanup system that removes tar, particulate matter, and gaseous pollutants;
- Two nominal 14.8 MW_{gross} BPG-fueled Solar T-130 combustion turbine-electrical generators (CT);
- Two supplementary-fired heat recovery steam generators (HRSG) with BPG-fueled duct burners (DB);
- A flare system, cooling towers and an auxiliary boiler;
- Two CT/HRSG exhaust stacks and a char/tar combustor exhaust stack; and,
- A nominal 20.7 MW_{gross} steam turbine-electrical generator (STG).

Emissions of nitrogen oxides (NO_X) in each CT/DB exhaust (HRSG stack) will be reduced with a selective catalytic reduction (SCR) system and measured with a continuous emissions monitoring system (CEMS). A CEMS is also required for CO from each HRSG stack. A continuous opacity monitoring system (COMS) and a process monitor for CO are required for the char combustor exhaust stack.

This project creates the following new emissions units.

ID No.	Emission Unit Description
001	Biomass handling, storage and drying
002	Biomass gasifier with startup burner
003	Char combustor/olivine heater with startup burner and olivine handling equipment
004	Biomass product gas flare system
005	Biomass product gas cleanup system
006	Nominal 14.8 MW Solar Model No. T-130 BPG-fueled combustion turbine and duct-fired HRSG
007	Nominal 14.8 MW Solar Model No. T-130 BPG-fueled combustion turbine and duct-fired HRSG
008	Cooling towers
009	Auxiliary boiler with a maximum heat input rate of 62 MMBtu/hour from firing natural gas
010	Miscellaneous support systems

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility has units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is not a major stationary source as defined in Rule 62-210.200, F.A.C. and is not subject to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

REGULATED POLLUTANTS

The primary regulated pollutants emitted from this project are: carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Small or negligible quantities of other pollutants will be emitted.

1. Permitting Authority: The permitting authority for this project is the Bureau of Air Regulation, Division of Air Resource Management, Florida Department of Environmental Protection (Department). The Bureau of Air Regulation's mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to the Title V Section of the same office.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northwest District Office at 160 Governmental Center, Suite 308, Pensacola, Florida 32502-5794. The telephone number of the district office is 850/595-8300. Copies of these documents shall also be submitted to the Northwest District's Branch Office at 630-3 Capital Circle NE, Tallahassee, Florida 32301. The telephone number of the branch office is 850/488-3704.
3. Appendices: The following Appendices are attached as part of this permit:
   a. Appendix A. Citation Formats and Glossary of Common Terms;
   b. Appendix B. General Conditions;
   c. Appendix C. Common Conditions;
   d. Appendix D. Common Testing Requirements;
   e. Appendix E. Biomass Feedstock Properties and Control Plan;
   f. Appendix F. NSPS – Standards of Performance Small Industrial Commercial-Institutional Steam Generating Units; and,
   g. Appendix G. NSPS – Standards of Performance for Stationary Combustion Turbines.
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(a), F.A.C.]
8. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V air operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V air operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

9. Financial Assurance Required: Prior to commencement of construction, the permittee shall post a payment bond in favor of the State of Florida Department of Environmental Protection in the amount of two million dollars ($2,000,000) to cover the cost of removal of all constructed facilities and equipment from the subleased premises as well as restoring the site to its original condition or conversion of the biomass energy production facility to another type of alternative energy production facility as required by the sublease agreement between the Florida State University Board of Trustees and the Permittee dated February 2, 2007. This bond may also be used at the discretion the Florida Department of Environmental Protection for the removal of any items from the site including but not limited to: wood, reagents such as ammonia, other fuels (including tars). [Rules 62-4.110, and 62-4.210(1)(c), F.A.C.]

10. Objectionable Odors Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

    {Note: An objectionable odor is defined in Rule 62-210.200(Definitions), F.A.C., as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance.}

11. Open Burning Prohibited: No person shall ignite, cause to be ignited, or permit to be ignited, any material which will result in any prohibited open burning as regulated by chapter 62-256, F.A.C.; nor shall any person suffer, allow, conduct or maintain any prohibited open burning. [Rule 62-256.300, F.A.C.]

12. Stack Design Requirement: Stacks shall be designed in accordance with the principles of good dispersion. Ambient dispersion modeling shall be conducted to insure that stack diameters, heights and placement are optimized with respect to physical features on the site and to insure compliance with the national ambient air quality standards. A stack design and dispersion analysis shall be provided to the Department upon completion of the front-end engineering design (FEED). [Rule 62-4.070(3)]

13. Facility-wide Emissions Report: The owner or operator shall submit an Annual Operating Report (AOR) for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) to the Department annually pursuant to subsection 62-210.370(3), F.A.C. Using the computation methods described in 62-210.370(2), F.A.C., the required AOR shall also include a demonstration that facility emissions of NO_X, CO, SO_2, VOC and PM/PM_{10} are each less than 250 tons per year (TPY).

A. Biomass Handling, Storage and Drying (EU-001)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
001	Biomass handling, storage and drying system

The feedstock will consist of woody biomass or crops that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. The woody biomass and crop feedstock properties are given in Appendix E along with a plan for quality control. Deliveries will be made in shipments of approximately 100 railroad cars per shipment to the site approximately every 7 to 10 days. 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 will be conveyed to an unfired dryer and then conveyed to the gasification process area.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a biomass handling, storage and drying system consisting of the following equipment.
   a. The railcar unloading system shall be covered and biomass unloaded from the bottom.
   b. The emergency truck unloading system shall also be covered.
   c. Belt conveyor systems #BC1 through #BC6 shall have totally enclosed head boxes, chutes and skirtboard systems to contain the fuel as well as prevent dust generation at the transfer points.
   d. The biomass storage pile shall be covered to keep material dry and minimize dust.
   e. The biomass dryer shall use thermal heat transfer (no additional combustion) to dry biomass prior to gasification.
   f. The half-day storage/feeder bin shall be enclosed and include a spreader conveyor, a bin vent filter and a bottom screw feeder for unloading.
   g. The bucket elevator shall be enclosed.
   h. Baghouses: Based on the preliminary design, the permittee shall install the following baghouses.
      1) Baghouse #1 shall control dust from the transfer points and belts on the BC#1 and BC#2 conveyor systems as well as the railcar and truck unloading systems designed for a nominal flow rate of 1,000 standard cubic feet per minute (scfm) exhausted at ambient temperature.
      2) Baghouse #2 shall control dust from the transfer points and belts on the BC#3 through BC#6 conveyor systems and the bucket elevator designed for a nominal flow rate of 1,000 scfm exhausted at ambient temperature.
      3) Baghouse #3 shall control dust from the thermal heat transfer biomass dryer designed for a maximum volumetric flow rate of a nominal 110,000 scfm at approximately 175° F.

      Each baghouse shall be designed and maintained to achieve an outlet dust loading rate of 0.03 grains per dry standard cubic feet (gr/dscf) of exhaust. New and replacement bags shall meet this specification based on vendor information.
   i. A bin vent filter shall control dust from the half day storage/feeder bin. The filter shall be designed and maintained to control at least 99.8% of the inlet dust loading designed for a nominal feed rate of 1,000 tons per day (TPD), wet basis. New and replacement filters shall meet this specification based on vendor information.

j. Based on the final design needs, additional baghouses may be installed as necessary to control fugitive dust from material handling and storage. Should the preliminary design change, the permittee shall provide final design details for all baghouses in the application for a Title V air operation permit along with a concurrent modification of this air construction permit.

[Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

PERFORMANCE RESTRICTIONS

3. Approximate Capacities: Each rail car will unload approximately 80 to 90 tons of biomass with an estimated moisture content of 30%. The covered storage area will hold approximately 10 to 14 days of feedstock (approximately 10,000 to 14,000 tons of wet biomass). The dryer will dry approximately 1000 tons per day (TPD) of wet biomass per day and the feeder will transfer approximately 730 tons of dry biomass feedstock to the gasifier. [Application No. 0730109-001-AC; and Rule 62-210.200(PTE), F.A.C.]

4. Restricted Operation: The hours of operation of are not limited (8,760 hours per year). [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Objectionable Odor: The permittee shall handle, store and dry the biomass so as not to cause, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

6. Fuels: Municipal Solid Waste (MSW) is prohibited from use at this facility. The fuel shall consist of woody biomass as described in Appendix-E - Woody Biomass Feedstock Properties and Control Plan of this permit. Inspection and testing procedures describe in Appendix-E shall be followed to insure that appropriate woody biomass is used as fuel and that MSW is not used as fuel.

EMISSIONS STANDARDS

7. Opacity Standard: In accordance with EPA Method 9, visible emissions from any baghouse and vent filter shall not exceed 5% opacity based on a 6-minute average. [Rules 62-4.070(3) and 62-297.310(7)(c), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

8. Initial Compliance Tests: As determined by EPA Method 9, the emissions unit shall be tested for 30 minutes to demonstrate initial compliance with the opacity standard within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

9. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the emissions unit shall be tested in accordance with EPA Method 9 for 30 minutes to demonstrate compliance with the opacity standard. [Rule 62-297.310(7)(a)4, F.A.C.]

10. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

RECORDS AND REPORTS

11. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

B. Biomass Gasifier (EU-002)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
002	Biomass gasifier with startup burner

The feedstock will be converted in the gasifier by pyrolysis to biomass product gas (BPG) in a circulating fluidized bed (CFB) of hot olivine (a special sand) and uses steam as the gasification medium. During the process, the olivine cools and the biomass feed breaks down to produce BPG including tar, char and ash. Cooled olivine and char are captured in the gasifier cyclones and returned to the char combustor to support combustion and reheat the olivine. The BPG from the gasifier cyclone is cooled in a heat exchanger and then cleaned as described in EU 005or flared as described in EU 004.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a gasifier consisting of the following equipment: CFB gasifier vessel; natural gas-fueled startup burner; and cyclones.
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Cyclone Separators: One cyclone separator shall be designed, installed and maintained to remove char and olivine from the raw BPG and recirculate it to the char combustor for combustion of the char and reheating of the olivine. Another cyclone separator shall be designed and maintained to remove remaining coarse solids ash prior to BPG cleanup or flaring.
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Gasifier Capacity: The nominal gasifier feed capacity is 730 tons per day of dry biomass feedstock.
   [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]

4. Gasifier Startup Burner Capacity: The nominal heat input rating of the natural gas-fueled startup burner is 25 mmBtu per hour. [Application No. 0730109-001-AC]

5. Restricted Operation: The hours of operation of the gasifier are not limited (8,760 hours per year). The gasifier startup burner may be used only for the purpose of starting up the gasifier.
   [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]

6. Fuel: Other than the natural gas for the start-up burner, only woody biomass as described in Appendix - E-Woody Biomass Feedstock Properties and Control Plan, shall be used as fuel. Municipal Solid Waste is prohibited from use at this facility.

7. Material Storage: Operational procedures to minimize spontaneous combustion for storage of woody biomass materials shall be used and include the following:
   a. Incoming unprocessed materials shall be stored in windrows or piles with a clear area around each pile that is equal to the height of the pile;
   b. Mixing new material with older material on the site shall be avoided, and an area shall be thoroughly cleaned before starting a new pile;
   c. Storage sites shall be level and on firm ground;
   d. Temperatures of storage piles shall be monitored;
   e. Concentrations of fine materials during pile build-up shall be avoided; and
   f. Pile compaction shall be avoided.

   [Rule 62-4.070(3), F.A.C.]

NSPS APPLICABILITY

8. NSPS Subpart Dc Applicability: The gasifier startup burner is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial or Institutional Boiler.. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements. The applicable conditions are given in Appendix F. [Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units].

C. Char Combustor (EU-003)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
003	Char combustor/olivine heater with startup burner and olivine handling equipment

Olivine and char captured in the gasifier cyclones and tars (returned from downstream BPG cleaning system) are fed to the char combustor. Air is introduced at the bottom of the vessel and supports combustion of the char and tars in a circulating fluidized bed (CFB) of olivine. Heated olivine is captured in the char combustor cyclones and returned to the gasifier to affect pyrolysis. Exhaust gas from the char combustor passes through a olivine cyclone and a hot ash cyclone, is cooled in a heat exchanger and then filtered in a baghouse.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a char combustor/olivine heater system consisting of the following equipment: Olivine storage silo; CFB char combustor vessel; natural gas-fueled startup burner; cyclones and a fabric filter baghouse.
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
2. Cyclone Separators: One cyclone separator shall be designed, installed and maintained to remove the heated olivine from the char combustor exhaust and recycle it back to the gasifier (EU 001). Another cyclone separator shall be designed, installed and maintained to remove most of the hot gasification ash prior to further particulate removal in one of the fabric filter baghouses described below.
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
3. Baghouses: The permittee shall install and maintain the following baghouses.
   a. Exhaust from the olivine storage silo shall be controlled by a baghouse designed and maintained to limit PM/PM_{10} emissions to 0.015 grains per standard cubic feet (gr/dscf) or better.
   b. Exhaust from the second char combustor cyclone (ash) separator shall be further controlled by a separate baghouse designed and maintained to 0.015 gr/dscf or better.

   Exhaust from these baghouses discharges directly to the ambient air. New and replacement bags shall meet these specifications based on vendor information. Should the preliminary design change, the permittee shall provide final design details for all baghouses and controls in the application for a Title V air operation permit along with a concurrent modification of this air construction permit.

   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
4. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emissions of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

PERFORMANCE RESTRICTIONS

5. Char Combustor Capacity: The nominal heat input rating of the char combustor is 124 mmBtu per hour.
   [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]
6. Char Combustor Startup Burner Capacity: The nominal heat input rating of the natural gas-fueled startup combustor is 17 mmBtu per hour. [Application No. 0730109-001-AC]
7. Restricted Operation: The hours of operation of the char combustor are not limited (8,760 hours per year). The char combustor startup burner may be used only for the purpose of starting up the char combustor.
   [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS APPLICABILITY

8. NSPS Subpart Dc Applicability: The char combustor startup burner is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c, Reporting and Recordkeeping Requirements. The applicable requirements are given in Appendix F.
[Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units].

EMISSIONS STANDARDS

9. Visible Emissions Standard – Char Combustor: In accordance with EPA Method 9, visible emissions from the char combustor baghouse shall not exceed 10% opacity on a 6-minute average as measured by a continuous emissions monitoring system (COMS). [Rules 62-4.070(3)]

10. Visible Emissions – Other Baghouses: In accordance with EPA Method 9, visible emissions from other baghouses in this section shall not exceed 5% opacity based on a 6-minute average.
[Rules 62-4.070(3) and 62-297.310(7)(c), F.A.C.]

11. Particulate emission (PM/PM_{10}) standard: PM/PM_{10} emissions from the char combustor shall not exceed 10.0 pounds per hour (lb/hr) as demonstrated by initial and annual compliance tests.
[Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

12. Nitrogen Oxides (NO_X) standard: NO_X emissions from the char combustor shall not exceed 10.0 lb/hr as demonstrated by initial and annual compliance tests.
[Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

13. Carbon monoxide (CO) standard: Emissions of CO from the char combustor exhaust stack shall not exceed 10.0 lb/hr as demonstrated by initial and annual compliance tests. In addition, three quarterly compliance tests shall be conducted between the initial compliance test and the first annual compliance test.
[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

14. Dioxin/furan: Dioxin/furan emissions shall meet a design value of 0.15 toxic equivalent nanograms/dry standard cubic meter at 7% oxygen (TEQ ng/dscm @7% O_2) demonstrated by an initial compliance test no later than 180 days after initial operation. Thereafter an annual compliance test shall be performed during each federal fiscal year (October 1st to September 30th) to show that the dioxin/furan standard is met. If exceeded during the initial compliance test, the applicant shall: design and install an activated carbon injection system; or modify the char combustor, its riser, duct work, temperature controls, heat exchanger or baghouse; or make other process changes within 180 days of the failed test as necessary to meet the design value. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

15. COMS: A continuous opacity monitoring system (COMS) shall be installed, calibrated, operated, and maintained in the char combustor exhaust stack, after the baghouse, in a manner sufficient to demonstrate continuous compliance with the opacity standards specified in this section. Opacity shall be based on a 6-minute block average computed from at least one observation (measurement) every 15 seconds. For the COMS, the 6-minute block averages shall begin at the top of each hour. [Rule 62-4.070(3), F.A.C.]

16. COMS Certification: The COMS required by this permit shall be installed prior to startup. Within 60 calendar days of achieving the first gasifier startup, the owner or operator shall certify the COMS. Upon certification of the COMS, the owner or operator shall demonstrate compliance with all applicable standards as specified in this permit. [Rule 62-4.070(3)]

17. CO Process Monitor: At least one process monitor shall be installed at an appropriate point between the ash cyclone and the exhaust stack to continuously monitor CO content in the process gases to enable the operator to properly operate the unit while minimizing emissions of CO, opacity, PM/PM_{10} and D/F. The data from the process monitors shall be available at the facility for Department inspection and in a suitable engineering format such as parts per million by volume (ppmv). The process monitor data shall be used in conjunction with the annual stack test data to calculate annual emissions as required in Section 2, Specific Condition 13. [62-4.070(3), F.A.C.]

18. Visible Emissions Compliance Tests: The olivine silo baghouse shall be tested for 30 minutes to demonstrate initial compliance with the opacity standard within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit. During each federal fiscal year (October 1st to September 30th), the emissions unit shall be tested in accordance with EPA Method 9 for 30 minutes to demonstrate compliance with the opacity standard. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

19. CO, PM/PM_{10}, NO_X and Dioxin/Furan Compliance Tests: The char combustor exhaust stack shall be tested to demonstrate initial compliance with the CO, PM/PM_{10}, NO_X and dioxin/furan standards no later than 180 days after initial operation. During each federal fiscal year (October 1st to September 30th), the char combustor shall be tested to demonstrate compliance with the CO, PM/PM_{10}, NO_X and dioxin/furan standards. [Rule 62-4.070(3), F.A.C.]

20. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

21. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
EPA 1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis and Moisture Content. Methods shall be performed as necessary to support other methods.
EPA 5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
EPA 7E	Determination of NO_X Emissions (Instrumental). NO_X emissions testing shall be conducted with the air heater operating at the highest heat input possible during the test.
EPA 9	Visual Determination of Opacity.
EPA 10	Measurement of Carbon Monoxide Emissions (Instrumental). The method shall be based on a continuous sampling train.
EPA 23	Measurement of Dioxin/Furan Emissions.

RECORDS AND REPORTS

22. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

D. Flare System (EU-004)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
004	Biomass product gas flare systems

Raw BPG from the biomass gasifier (EU-002) may be flared to the extent necessary and not sent to the BPG cleanup system (EU-005). Cleaned, sweetened BPG from the cleanup system may be flared to the extent necessary and not further processed for use in the combustion turbines or duct burners (EU 006 and 007).

EQUIPMENT

1. Equipment: The permittee is authorized to construct two BPG flare systems, including one for the raw BPG and one for cleaned BPG, with continuous pilots and combustion chambers to destroy unused BPG. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Approximate Capacities: Each flare system is designed to combust biomass product gas with a nominal heat input rate of 150 mmBtu per hour. Natural gas may be used as fuel for the pilots.
   [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]

3. Restricted Operation: Although the hours of operation of are not limited, the flare systems shall only be used to flare BPG gas during startup, planned shutdown, and emergency shutdown (e.g. combustion turbine, duct burner or gasifier trip).
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

RECORDS AND REPORTS

4. Records: The permittee shall record in a written log the duration of each flare event and the reason for flaring. If requested by the Compliance Authority, the permittee shall provide a copy of these records or a summary of these records. [Rule 62-4.070(3), F.A.C.]

5. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the gasifier/combustor, associated burners and flare system are minimized. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of these systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. The flare pilots shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

   [Rules 62-4.070(3) F.A.C.]

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
005	BPG cleanup consisting of specialized oil scrubbers, an aqueous scrubber with a caustic section and an absorption system designed to concentrate hydrogen (H_2) from a slipstream of the product gas.

The cooled raw BPG from the gasifier/coarse solids cyclone (EU-002) is treated to remove tars and finer particles in an oil-based gas washer. Tars are returned to support combustion in the char combustor (EU-003). Removal of NH_3, H_2S and hydrogen chloride (HCl) will be accomplished in a wet scrubber that will include a section that will scrub H_2S using caustic soda (NaOH). Cooled, sweetened, and cleaned BPG is then compressed or boosted for delivery to the combustion turbines/duct burners (EU-006 and 007), flared (EU-004) or further treated to provide a hydrogen (H_2) gas stream to Florida State University (FSU).

EQUIPMENT

1. Equipment: The permittee is required to construct a BPG cleanup system consisting of the following equipment.
   a. A two-stage scrubber that utilizes specialized oils and is designed to remove heavy tars in the first stage and light tars in the second stage. The heavy and light tars are then recycled back to the char combustor.
   b. An aqueous scrubber that is designed to remove inorganic impurities.
   c. An absorption system that is designed to concentrate H_2 from a slipstream of BPG. The H_2 gas stream will be transported by pipeline to a FSU research facility. The off-gas from the slipstream will be blended back with the BPG and sent to the power generation systems for use as a fuel.

   None of the control systems discharge directly to the ambient air.
   [Application No. 0730109-001-AC and Rules 62-4.070(3), F.A.C.]

TAR HANDLING AND STORAGE

2. Tars shall be continuously returned to the char combustor and not accumulated, stored or disposed.

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
006	One nominal 14.8 MW BPG-fueled Solar T-130 CT and supplementary-fired HRSG with a nominal 28 mmBtu/hour BPG-fueled DB. Steam from in the HRSG is used in the shared nominal 20.7 MW STG.
007	One nominal 14.8 MW BPG-fueled Solar T-130 CT and supplementary-fired HRSG with a nominal 28 mmBtu/hour BPG-fueled DB. Steam from in the HRSG is used in the shared nominal 20.7 MW STG.

EQUIPMENT

1. CT: The permittee is authorized to install, tune, operate and maintain a combined cycle combustion turbine system consisting of the following equipment: two nominal 14.8 MW BPG-fueled Solar T-130 CT; two inlet air filtration systems; two automated CT control systems; two HRSG with BPG-fueled DB systems; two HRSG stacks; and a shared nominal 20.7 MW steam turbine-electrical generator. Natural gas will be used during commissioning and during startups, malfunctions and shutdowns.
[Application No. 0730109-001-AC]

2. SCR Systems: The permittee shall install an SCR system for each CT/HRSG exhaust stream to control NO_X emissions and further assist in dioxin and furan destruction. Each SCR system will consist of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. Each SCR system shall be designed, constructed and operated to achieve the permitted levels of NO_X emissions. The SCR system shall be designed to achieve a maximum ammonia slip level of 10 ppmvd @ 15% oxygen.

   {Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}

   [Application No. 0730109-001-AC and Rule 62-4.070(3), F.A.C.]

3. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. Ammonia shall be injected as necessary to ensure compliance with the permitted levels of NO_X emissions specified in this permit. [Rules 62-210.650 and Rule 62-4.070(3), F.A.C.]

4. NO_X CEMS: In accordance with §60.4335(b) and §60.4345, the permittee shall install, calibrate, operate and maintain a CEMS to continuously monitor and record NO_X emissions and from each combustion turbine exhaust. [Application No. 0730109-001-AC; Rule 62-4.070(3), F.A.C.; and Subpart KKKK in 40 CFR 60]

5. CO CEMS: The permittee shall install, calibrate, operate and maintain a CEMS to continuously monitor and record CO emissions and from each combustion turbine exhaust.
[Application No. 0730109-001-AC; Rule 62-4.070(3), F.A.C]

PERFORMANCE RESTRICTIONS

6. Authorized Fuels: The only authorized fuels for the combustion turbines and duct burner systems are:

   a. Product gas from the BPG cleanup system containing no more than 0.02% sulfur by volume, 30-operating-day basis.

   b. Natural gas containing no more than 20 grains of sulfur per 100 standard cubic feet (gr S/100 SCF).

   {Permitting Note: only BPG can be burned in the DB, natural gas cannot be used}

   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

7. Permitted Capacities:

   a. *CT*: The nominal heat input rating of each CT is 147 mmBtu/hour. This rate is based on a compressor inlet temperature of 59 °F, International Organization for Standardization (ISO) conditions, and the lower heating value (LHV) of the BPG or natural gas. Heat input rates will vary depending upon combustion turbine characteristics, ambient conditions, alternate methods of operation and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

   b. *DB Systems*: The nominal heat input rating of each DB located within each HRSG is 28 mmBtu per hour based on the LHV of BPG.

   The estimated LHV is 435 Btu/scf for BPG and 980 Btu/scf for natural gas.
   [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]

8. Restricted Operation: Each CT shall use no more than 112.5 MMscf of natural gas during any consecutive 12 month period (equivalent to 750 hours of firing natural gas at permitted capacity). The hours of operation are not otherwise limited (8,760 hours per year).
   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

9. Authorized Method of Operation: Both CT are permitted to operate only as part of a combined cycle system. [Application No. 0730109-001-AC]

NSPS APPLICABILITY

10. NSPS Subpart KKKK Applicability: The CT and associated DB are subject to all applicable requirements of 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines which applies to combustion turbines and duct burners constructed after February 18, 2005.
    [Rule 62-204.800(7)(b), F.A.C. and 40 CFR 60.4300, NSPS - Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (see Appendix G)].

EMISSION LIMITS

11. Emission Standards: The following standards are at least as stringent as the Subpart KKKK limits described in Condition 10 above and in Appendix G of this permit. They also include more stringent limits to insure that the facility PSD-pollutant emissions are less than the respective major stationary source thresholds. Emissions from the CT/HRSG system shall not exceed the following standards.

Pollutant	Method of Operation	Initial/Annual Stack Test 3-Run Average		CEMS-Based Averages [h]	
		ppmvd [a]	lb/hr [g]	ppmvd [a]	lb/hr
CO [b]	CT (BPG)	50.0	17.2	50.0, 30 days rolling	N/A
	CT & DB (BPG)	50.0	21.4		
	CT (NG)	NA	12.1	N/A	
	CT All Modes	N/A	21.4	N/A	21.4, 12-month rolling, rolled monthly

F. Combustion Turbines and Duct Burners (EU-006, EU-007)

Pollutant	Method of Operation	Initial/Annual Stack Test 3-Run Average		CEMS-Based Averages [h]	
		ppmvd [a]	lb/hr [g]	ppmvd [a]	lb/hr
NO_X [c]	CT (BPG)	32.5	17.2	32.5 30 days rolling [g]	N/A
	CT & DB (BPG)	32.5	19.2		
	CT (NG)	25.0	8.8	25.0 30 day rolling [h]	
	CT All Modes			N/A	19.2 lb/hr 12-months rolling, rolled monthly
PM/PM_{10} [d]	All Modes	N/A	10.0	N/A	
		Fuel Specification: 20 gr S/100 SCF in NG and 0.02% S in BPG			
		Visible emissions shall not exceed 10% opacity for each 6-minute block average.			
SAM/SO_2 [e]	All Modes	20 gr S/100 SCF in NG and 0.02% S in BPG [h]			
Ammonia [f]	CT, All Modes	10	NA	NA	

a. Parts per million by volume dry corrected to 15% oxygen

b. Continuous compliance with the 30 day rolling average CO standard shall be demonstrated based on data collected by the required continuous emissions monitoring system (CEMS). The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for normal BPG and the DB modes. The twelve month mass emission rate values rolled monthly determined by data collected by the CEMS shall be used to demonstrate yearly emission limits in tons per year (tpy) proving avoidance of PSD.

c. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for normal BPG and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2). Continuous compliance with the 30 day rolling average NO_X standards shall be demonstrated based on data collected by the required CEMS. Twelve month mass emission rate values rolled monthly determined by data collected by the CEMS shall be used to demonstrate yearly emission limits in tons per year (tpy) proving avoidance of PSD.

d. After the initial compliance test the sulfur fuel specification combined with the efficient combustion design and operation of the CT shall indicate compliance. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

e. The fuel sulfur specification effectively limits the potential emissions of SAM and SO_2 from the CT. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur or by fuel supplier/vendor reports as detailed in the draft permit.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

g. The mass emission rate standards are based on a turbine inlet condition of 59 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. CEMS monitoring compliance shall in accordance with the 40 CFR 60, NSPS, Subpart KKKK for NO_X and SO_2 as described in 60.4380(b)(1).

[Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

12. Ammonia Slip: Each SCR system shall be designed to achieve a maximum ammonia slip of 10 ppmvd @ 15% oxygen. Actual ammonia slip levels shall not exceed 10 ppmvd @ 15% oxygen as determined by EPA Method CTM-027 based on the average of three test runs. If tests indicate an ammonia slip level greater than 10 ppmvd @ 15% oxygen, the permittee shall:

    a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

    b. Before the ammonia slip exceeds 10 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 10 ppmvd corrected to 15% oxygen; and

    c. Test and demonstrate that the ammonia slip is less than 10 ppmvd corrected to 15% oxygen within 45 days after completing the corrective actions.

    Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 10 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.
    [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

13. Definitions Related to Excess Emissions: Rule 62-210.200(Definitions), F.A.C. defines the following terms.

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

14. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

15. Excess Emissions Calculations: The following conditions apply only to the SIP-based emissions standards specified above in this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.

    a. *CO Emissions Standards*: No excess emissions provisions are made for excess CO emissions.

    b. *NO_X Emissions*: Excess NO_X emissions based on the 30-day rolling average standard shall be calculated in accordance with the NSPS Subpart KKKK provisions. NO_X emissions in excess of the 12-month rolling total are not allowed.

    c. *Opacity*: As determined by EPA Method 9, visible emissions from each combustion turbine during startup and shutdown shall not exceed 20% opacity based on 6-minute averages. Excess visible emissions resulting from malfunction shall be permitted providing: (1) best operational practices to minimize emissions are adhered to, and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period.

GENERAL COMPLIANCE REQUIREMENTS

MONITORING

16. Fuel Sulfur Monitoring: The permittee shall conduct the following monitoring to demonstrate compliance with the fuel sulfur specifications.

    a. For BPG, the permittee shall monitor the fuel sulfur content in accordance with the provisions of Section 60.4370 in NSPS Subpart KKKK of 40 CFR 60. In addition, the permittee shall sample and analyze the BPG for the heating value at least once per week.

    b. For natural gas, the permittee shall either obtain reliable fuel sulfur data from the natural gas pipeline vendor or analyze a monthly sample of natural gas for the fuel sulfur content.

    [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

RECORDS AND REPORTS

17. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each combustion turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). This shall be achieved through monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of Appendix D in 40 CFR 75 and recording the data using a monitoring component of the CEMS system required above. [Rule 62-4.070(3), F.A.C. and 40 CFR 75]

18. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month and the previous consecutive 12 months: total heat input rate to the combustion turbine from each fuel (MMBtu); the total heat input rate to the duct burner (MMBtu); and the 12-month rolling total of NO_X emissions (tons). Annual NO_X emissions shall be determined in accordance with Rule 62-210.370, F.A.C., which is included in Appendix C of this permit. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. Fuel consumption shall be monitored in accordance with the provisions of Appendix D in 40 CFR 75. [Rules 62-4.070(3), F.A.C.]

19. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix D. [Rule 62-297.310(8), F.A.C.]

PERFORMANCE TESTS TEST

20. Initial Compliance Tests: The combustion turbines shall be tested to demonstrate initial compliance with the emissions standards for PM/PM_{10}, opacity and ammonia slip. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. The combustion turbines shall demonstrate compliance with the NO_X standard in accordance with the methods specified in NSPS Subpart KKKK of 40 CFR 60. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the combustion turbines shall be tested to demonstrate compliance with the emissions standards for opacity and ammonia slip. The combustion turbines shall demonstrate compliance with the NO_X standard in accordance with the methods specified in NSPS Subpart KKKK of 40 CFR 60. [Rule 62-297.310(7)(a)4, F.A.C.]

22. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

23. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of NO_X Emissions from Stationary Sources.
9	Visual Determination of the Opacity of Emissions from Stationary Sources.
10	Determination of CO Emissions from Stationary Sources The method shall be based on a continuous sampling train.
19	Determination of SO_2 Removal Efficiency and PM, SO_2 and NO_X Emission Rates Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source.

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

CONTINUOUS MONITORING REQUIREMENTS

24. CEMS: The permittee shall install, calibrate, maintain and operate CEMS and a diluent monitor to measure and record the emissions of CO and NO_X from each CT in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated and properly functioning within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup and prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

    b. *NO_X Monitor:* The NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

25. CEMS Data Requirements:

    a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emissions rates shall be corrected to ISO conditions.

    b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

    c. *12-month Rolling Averages:* Compliance with the long-term emission limit for NO_X and CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

    d. *30 unit operating day Rolling Average:* Compliance with this rolling average is as described in 40 CFR 60.4380(b)(1).

    e. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

    [Rules 62-4.070(3), F.A.C.]

26. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the CT load condition. [Rules 62-4.070(3)]

G. Cooling Towers (EU-008)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
008	Cooling towers

EQUIPMENT DESIGN

1. Cooling Tower Design: The permittee is authorized to construct a cooling tower system for the steam turbine and cooling of compressor gases consisting of the following equipment.

   a. One 2-cell cooling tower with mist eliminators designed for a nominal air flow rate of 1,061,664 acfm, a circulating water flow rate of 7056 gpm and a drift rate of 0.002% of the circulating water flow rate.

   b. One 3-cell cooling tower with mist eliminators designed for a nominal air flow rate of 114,386 acfm, a circulating water flow rate of 3800 gpm, and a drift rate of 0.005% of the circulating water flow rate.

   [Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Hours of Operation: Operation of the cooling towers is not restricted (8,760 hours per year). [Application No. 0730109-001-AC and Rule 62-210.200 (PTE), F.A.C.]

3. Circulating Water Flow Rate: Upon request, the applicant shall provide a means for determining the circulating water flow rate through the new cooling towers. [Rule 62-4.070, F.A.C.]

4. Drift Rate: The permittee shall provide certification along with the application for Title V air operation permit that the cooling towers were constructed and installed to the design specifications in this permit. After this certification is provided, the cooling tower will be considered an unregulated emissions unit. [Rules 62-4.070 and 62-210.200 (PTE), F.A.C.]

H. Auxiliary Boiler (EU-009)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
009	Auxiliary boiler fires natural gas with a maximum heat input rate of 62 MMBtu/hour to start up biomass gasification system. Exhaust gases exit a 2.75 feet diameter stack that is 50 feet tall at 29,000 acfm and 296° F.

EQUIPMENT

1. Auxiliary Boiler: The permittee is authorized to install an auxiliary boiler rated at 62 MMBtu/hour of heat input from firing natural gas. The auxiliary boiler shall only be operated for purposes of starting up the gasification system. [Application No. 0730109-001-AC]

PERFORMANCE RESTRICTIONS

2. Authorized Fuel: The auxiliary boiler shall only fire natural gas with a maximum fuel sulfur content of 20 grains/100 scf.
[Application No. 0730109-001-AC; and Rules 62-210.200(PTE) and 62-296.406(BACT), F.A.C.]
3. Permitted Capacity: The maximum heat input rate of the auxiliary boiler is 62 mmBtu/hour based on a 24-hour average. [Application No. 0730109-001-AC and Rule 62-210.200(PTE), F.A.C.]
4. Restricted Operation: The auxiliary boiler shall fire no more than 31.6 mmscf of natural gas during any consecutive 12 months (equivalent to 500 hours of operation at permitted capacity). The hours of operation of are not otherwise limited.
[Application No. 0730109-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

REGULATORY APPLICABILITY

5. Small Boiler BACT: The auxiliary boiler is subject to the requirements of Rule 62-296.406, F.A.C., which includes a determination of the Best Available Control Technology (BACT) for PM and SO_2 emissions. For this project, BACT for PM and SO_2 emissions is determine to be the firing of natural gas as the only authorized fuel. [Rule 62-296.406, F.A.C.]
6. NSPS Subpart Dc Applicability: The auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial or Institutional Boilers. Specifically, this emission unit shall comply with 40 CFR 60.48c Reporting and Recordkeeping Requirements.
[Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units with the applicable conditions attached as Appendix F]

EMISSIONS STANDARDS

7. Opacity Standard: In accordance with EPA Method 9, visible emissions shall not exceed 20% opacity except for one 6-minute period per hour that shall not exceed 27% opacity.
[Application No. 0730109-001-AC; and Rule 62-296.406(BACT), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

8. Initial Compliance Tests: As determined by EPA Method 9, the emissions unit shall be tested to demonstrate initial compliance with the opacity standard within 60 days after achieving permitted capacity, but no later than 180 days after initial operation of the unit.
[Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

9. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the emissions unit shall be tested in accordance with EPA Method 9 to demonstrate compliance with the opacity standard. [Rule 62-297.310(7)(a)4, F.A.C.]

10. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

RECORDS AND REPORTS

11. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the heat input rate. [Rule 62-297.310(8), F.A.C.]

I. Miscellaneous Support Systems (EU-010)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
010	Miscellaneous support systems

EQUIPMENT DESIGN

1. Equipment: The permittee is authorized to construct the following support equipment for this project.

   a. A water treatment system for the boilers;

   b. An ash handling system; and

   c. Gas compressor systems for the biomass product gas and natural gas.

   [Application No. 0730109-001-AC]

Contents

Citation Formats and Glossary of Common Terms

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

Example: Permit No. AC50-123456 or Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

Citation Formats and Glossary of Common Terms

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

General Conditions

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S.. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (Rule 62-296.406, F.A.C. applies to auxiliary boiler);
    b. Determination of Prevention of Significant Deterioration (not applicable); and
    c. Compliance with New Source Performance Standards (NSPS Subpart KKKK applies to combustion turbines. NSPS Subpart Dc applies to auxiliary boiler and gasifier and char combustor startup burners).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Common Conditions

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Emissions Computation and Reporting
    a. *Applicability*. This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission

limitations of any air permit.

b. *Computation of Emissions*. For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

(1) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.

(a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.

(b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(2) Continuous Emissions Monitoring System (CEMS).

(a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

1) A calibrated flowmeter that records data on a continuous basis, if available; or

2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(c) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

(3) Mass Balance Calculations.

(a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the

process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

(4) Emission Factors.

a. An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

b. If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

(8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

c. *Annual Operating Report for Air Pollutant Emitting Facility*

Common Conditions

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

(a) All Title V sources.

(b) All synthetic non-Title V sources.

(c) All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

(d) All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by March 1 of the following year.

(4) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

[Rule 62-210.370, F.A.C.]

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the facility.

COMPLIANCE TESTING REQUIREMENTS

1. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

2. Applicable Test Procedures - Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

   c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

   [Rule 62-297.310(4), F.A.C.]

3. Determination of Process Variables

   a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

   b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

   [Rule 62-297.310(5), F.A.C.]

4. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

   a. *General Compliance Testing.*

      1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

      2. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall

not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

3. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for visible emissions, if there is an applicable standard.

4. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

[Rule 62-297.310(7), F.A.C.]

RECORDS AND REPORTS

5. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the following information.

   a. The type, location, and designation of the emissions unit tested.

   b. The facility at which the emissions unit is located.

   c. The owner or operator of the emissions unit.

   d. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

   e. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

   f. The date, starting time and end time of the observation.

   g. The test procedures used.

   h. The names of individuals who furnished the process variable data, conducted the test, and prepared the report.

   i. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

   j. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

Woody Biomass Feedstock Properties and Control Plan

BG&E WOODY BIOMASS FEEDSTOCK PROPERTIES

Background Information:

Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to woody biomass meaning trees and woody plants, including limbs, tops, trunks, needless, leaves, stalks and other woody parts, grown in a forest, woodland, rangeland environment, tree farm or agricultural crop farm. The term includes such materials generated in conjunction with the safe transmission power line management practices of the City of Tallahassee. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass including sander dust, wood chips, saw dust and bark.

According to BG&E, 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 available feedstock types for the TREC, including: sander dust; saw dust; rejects from round wood debarking; hogged fuel; processed butt cuts, and a vegetative crop. The woody biomass feedstock will be delivered to TREC via a train consisting of approximately 100 railcars per shipment at 7 to 10 day intervals.

The reject material from the round wood debarking may be obtained from strand board mills, plywood plants and wood pelletizing facilities in the region. 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.

Feedstock Handling Requirements and Control Plan:

1. Woody biomass feedstocks shall be obtained from vendors that certify that the woody biomass feed stocks they supply to TREC meet the definition of woody biomass specified above. In addition. the vendor must certify that the that the woody biomass does not contain any of the prohibited items listed in **Condition 9** below.
2. Any such vendor certification shall include, in legible fashion, the name of the vendor's representative making the certification as well as the representative's signature. The permittee shall retain records of the certifications for 5 years.
3. Woody biomass feedstock shall be delivered to TREC solely by train.
4. Each railcar of woody biomass feedstock shall be homogenous in nature.
5. For each original source of woody biomass feedstock, the permittee shall retain documentation of the original source's procedures to prevent the contamination of the woody biomass with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass.
6. The permittee shall retain documentation of the off-site material handling facility's procedures for receiving, segregating and loading the woody biomass from the original sources. In addition, the permittee shall retain documentation of the quality assurance procedures in place at the off-site handling facility to ensure the woody biomass is not contaminated with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass.
7. For each shipment of woody biomass, the permittee shall record the date received, the original source of the woody biomass and the quantity received, and the name, in a legible fashion, and signature of the individual(s) responsible for performing the visible inspection in **Condition 8**, below.
8. The permittee shall inspect each shipment of woody biomass upon receipt and during unloading for any material not specifically authorized by this permit. If the permittee identifies any such material, the material must be removed from the shipment and the material vendor notified. The rejected material must be disposed of following all applicable Department regulations. The permittee shall maintain a record of rejected materials, the amount of material rejected and the reason(s) for rejection.

9. The following items are not considered woody biomass and are expressly prohibited:
   a) those materials that are prohibited by state or federal law;
   b) woody biomass that has been chemically treated or processed;
   c) yard trash;
   d) municipal solid waste;
   e) paper;
   f) treated wood such as CCA or creosote;
   g) painted wood;
   h) wood from construction and demolition sites; and
   i) wood wastes from landfills.

   [Rules 62-4.070(3), 62-213.410, and 62-213.440, F.A.C.]

NSPS Subpart Dc - Small Industrial-Commercial-Institutional Steam Generating Units

A 62 MMBtu/hr auxiliary boiler firing natural gas that will be used to produce steam during start up of the STG is regulated under this NSPS. It is designated as Emissions Unit 009. In addition, the 25 MMBtu/hr gasified startup burner and the 17 MMBtu/hr char combustor startup burner are regulated under this NSPS. The startup burner for the gasifier is included in Emission Unit 002, while the startup burner for the char combustor is included in Emission Unit 003. The provisions of this Subpart may be provided in full upon request. These units are subject only to record keeping and reporting requirements since these combustion units fire only natural gas.

{Note: Only applicable definitions have been included.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e. , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

NSPS – Standards of Performance for Stationary Combustion Turbines

The TREC CT are regulated as Emissions Units 006 and 007. These gas turbines and the HRSG duct burners are part of the combined cycle unit. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK-- Standards of Performance for Stationary Combustion Turbines.

The full provisions may be provided in full upon request and are also available beginning at Section 60.4300 at:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr60_07.html .

Table 1 is a listing of the NO_X limits from Subpart KKKK that apply to the TREC project.

Table 1 to Subpart KKKK of Part 60. NO_X Emission Limits for New Stationary Combustion Turbines*

CT Type	CT Heat Input at Peak Load (HHV)	NO_X Emission Standard
New turbine firing natural gas	> 50 MMBtu/ hour and ≤ 850 MMBtu/hour	25 ppmvd at 15% oxygen
New turbine firing fuels other than natural gas	> 50 MMBtu/hour and ≤ 850 MMBtu/hour	74 ppmvd at 15% oxygen

*Only the portion of the table that includes the NO_X Requirements applicable to the TREC project.

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer

FROM: A.A. Linero AAL 10/24

DATE: October 24, 2008

SUBJECT: DEP File No. 0730109-001-AC
Tallahassee Renewable Energy Center
Biomass Integrated Gasification and Combined Cycle Unit

This project is subject to minor source preconstruction review. Attached for your review are the following items:

- Written Notice of Intent to Issue a Draft Air Construction Permit;
- Public Notice of Intent to Issue a Draft Air Construction Permit;
- Technical Evaluation and Preliminary Determination;
- Draft Air Construction Permit; and,
- P.E. Certification.

On April 3, 2008, Biomass Gas and Electric, LLC (BG&E) submitted an air permit application to construct the Tallahassee Renewable Energy Center (TREC) consisting of a nominal 42 megawatts (MW) biomass integrated gasification and combined cycle (BIGCC) unit and ancillary equipment. The Technical Evaluation and Preliminary Determination document provides a detailed description of the project and the rationale for issuance. The P.E. certification briefly summarizes the proposed project.

I recommend your approval of the attached Draft Air Construction Permit.

Attachments

PROFESSIONAL ENGINEER CERTIFICATION STATEMENT

Permittee:
Biomass Gas and Electric of Tallahassee, LLC
3500 Parkway Lane, Suite 440
Atlanta, Georgia 30092

DEP File No. 0730109-001-AC
Tallahassee Renewable Energy Center
Biomass Integrated Gasification Combined Cycle
Leon County, Florida

Project: To construct the Tallahassee Renewable Energy Center consisting of a nominal 42 megawatts (MWnet) biomass integrated gasification combined cycle unit and ancillary equipment. Details of the project are provided in the application available at:

www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm

The project did not trigger the rules for the Prevention of Significant Deterioration (PSD) of air quality and a determination of best available control technology was not required. The primary basis of the review was adherence to the new source performance standards applicable to the combustion turbines, duct burners, auxiliary boiler and startup burners. Conditions were included to insure that the facility emits less than 250 tons per year (TPY) of any PSD-pollutant.

The control equipment, testing requirements and emission limitations are given in the technical evaluation and preliminary determination and the draft permit to which this certification applies. These documents are available at the web link given above.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal to conduct a scale-up of the biomass product gas tar removal system based on a 4 MW (thermal) demonstration in France. I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features). Note that less than the typical level of detail was required given the demonstration nature of certain aspects of the project, such as the tar removal system. Per 403.061(18), F.S., my employer, the Florida DEP 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.*

10/24/08

Alvaro A. Linero, P.E. (Date)
Registration Number: 26032

ALVARO A. LINERO
LICENSE
NO. 26032
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

Livingston, Sylvia

From: Vielhauer, Trina
Sent: Thursday, November 06, 2008 11:53 AM
To: 'susiecaplowe@comcast.net'; Livingston, Sylvia; Walker, Elizabeth (AIR)
Cc: 'hopeforcleanwater@yahoo.com'; Linero, Alvaro
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Hi Susie,
For everyone that was copied on our email distribution, you have 14 days from receipt (count that date as day 1) to file a petition for a legal hearing. For those NOT copied on that distribution, they have 14 days from publication of notice to file a petition. That notice published tuesday so the deadline would be 11/17 for those not copied to petition.

Everyone's comment period ends 11/17 (14 days from publication).

Hope that is helpful.

trina
Trina Vielhauer

Sent from my BlackBerry Wireless Handheld

----- Original Message -----
From: susiecaplowe@comcast.net <susiecaplowe@comcast.net>
To: Livingston, Sylvia; Walker, Elizabeth (AIR)
Cc: Vielhauer, Trina; Susie Caplowe <susiecaplowe@comcast.net>; Joy Towles Ezell <hopeforcleanwater@yahoo.com>
Sent: Thu Nov 06 11:20:32 2008
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Hi Trina.
Can you please clarify the legal and public comment deadlines for the BGandE bimass plant.
Legal deadline began when?
Public comment began when?
Thank you. Susie
Sent via BlackBerry by AT&T

Livingston, Sylvia

From: Vielhauer, Trina
Sent: Monday, October 27, 2008 1:23 PM
To: Livingston, Sylvia
Subject: RE: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Got it!

From: Livingston, Sylvia
Sent: Monday, October 27, 2008 12:52 PM
To: 'glenn@biggreenenergy.com'
Cc: Fancher, Dick; 'sosbourn@golder.com'; 'forney.kathleen@epamail.epa.gov'; 'Abrams.Heather@epa.gov'; 'saulsj@leoncountyfl.gov'; 'proctorb@leoncountyfl.gov'; 'john.marks@talgov.com'; 'anita.favors.thompson@talgov.com'; Gibson, Victoria; 'gibbyj@earthlink.net'; 'hopeforcleanwater@yahoo.com'; 'daswim@gmail.com'; 'joecain1@comcast.net'; 'ronsaff@aol.com'; 'salters@magnet.fsu.edu'; 'sth@magnet.fsu.edu'; 'hluebkemann@comcast.net'; 'shereitte@gmail.com'; 'richard.gragg@famu.edu'; 'richardgraggiii@mac.com'; 'bobfulford@nettally.com'; 'anitald@embarqmail.com'; 'susiecaplowe@comcast.net'; 'dave@no-burn.org'; 'bradley@greenaction.org'; 'nseldman@ilsr.org'; 'dmellman@post.harvard.edu'; 'ring@tampabay.rr.com'; Linero, Alvaro; Read, David; Vielhauer, Trina; Walker, Elizabeth (AIR)
Subject: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Dear Sir/ Madam:

Attached is the official **Notice of Draft Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:

http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0730109.001.AC.D_pdf.zip

Additional project information can be found at www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm

Owner/Company Name: BG and E OF TALLAHASSEE, LLC
Facility Name: TALLAHASSEE RENEWABLE ENERGY CENTER
Project Number: 0730109-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION/ Biomass Integrated Gasification and Combined Cycle Unit
Facility County: LEON

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation at (850)488-0114.

Livingston, Sylvia

From: ANITA & MORRIS DAVIS [anitald@embarqmail.com]

Sent: Monday, October 27, 2008 1:11 PM

To: Livingston, Sylvia

Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Received documents

Anita Davis, FCAN/Jake Gaither Community Center
----- Original Message -----
From: "Sylvia Livingston" <Sylvia.Livingston@dep.state.fl.us>
To: glenn@biggreenenergy.com
Cc: "Dick Fancher" <Dick.Fancher@dep.state.fl.us>, sosbourn@golder.com, "forney kathleen" <forney.kathleen@epamail.epa.gov>, "Abrams Heather" <Abrams.Heather@epa.gov>, saulsj@leoncountyfl.gov, proctorb@leoncountyfl.gov, "john marks" <john.marks@talgov.com>, "anita favors thompson" <anita.favors.thompson@talgov.com>, "Victoria Gibson" <Victoria.Gibson@dep.state.fl.us>, gibbyj@earthlink.net, hopeforcleanwater@yahoo.com, daswim@gmail.com, joecain1@comcast.net, ronsaff@aol.com, salters@magnet.fsu.edu, sth@magnet.fsu.edu, hluebkemann@comcast.net, shereitte@gmail.com, "richard gragg" <richard.gragg@famu.edu>, richardgraggiii@mac.com, bobfulford@nettally.com, anitald@embarqmail.com, susiecaplowe@comcast.net, dave@no-burn.org, bradley@greenaction.org, nseldman@ilsr.org, dmellman@post.harvard.edu, ring@tampabay.rr.com, "Alvaro Linero" <Alvaro.Linero@dep.state.fl.us>, "David Read" <David.Read@dep.state.fl.us>, "Trina Vielhauer" <Trina.Vielhauer@dep.state.fl.us>, "Elizabeth Walker (AIR)" <Elizabeth.Walker@dep.state.fl.us>
Sent: Monday, October 27, 2008 12:52:16 PM (GMT-0500) America/New_York
Subject: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Dear Sir/ Madam:
Attached is the official **Notice of Draft Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0730109.001.AC.D_pdf.zip

Additional project information can be found at www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm

Owner/Company Name: BG and E OF TALLAHASSEE, LLC
Facility Name: TALLAHASSEE RENEWABLE ENERGY CENTER
Project Number: 0730109-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION/ Biomass Integrated Gasification and Combined Cycle Unit
Facility County: LEON

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other

Livingston, Sylvia

From: Donald Mellman [dmellmanmd@verizon.net]
Sent: Monday, October 27, 2008 1:51 PM
To: Livingston, Sylvia
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Ms. Livingston

I can & have viewed the documents.

Thank you so much for keeping me in the loop.

Best,

Donald L. Mellman, MD, MPH, MBA, FACS
1149 Shipwatch Circle
Tampa, FL 33602-5786
Mobile: 813-205-2702
E-fax:813-354-3623
dmellman@post.harvard.edu

On 10/27/08 12:52 PM, "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us> wrote:

> Dear Sir/ Madam:
> Attached is the official **Notice of Draft Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).
>
> **Click on the following link to access the permit project documents:**
> http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0730109.001.AC.D_pdf.zip
> <http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0730109.001.AC.D_pdf.zip>
>
> Additional project information can be found at
> www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm
> <file://www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm>

Livingston, Sylvia

From: Bob Fulford [bobfulford@nettally.com]
Sent: Monday, October 27, 2008 2:59 PM
To: Livingston, Sylvia
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Oops. Sorry.

231 Westridge Dr.
City
32304

PS I discovered why I could not download the recommended version of Acrobat. My system is too old. Windows 98

> ----- Original Message -----
> **From:** Livingston, Sylvia
> **To:** Bob Fulford
> **Sent:** Monday, October 27, 2008 1:44 PM
> **Subject:** RE: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC
>
> Mr. Fulford,
>
> Please send me your mailing address and I'll send it to you via certified mail.
>
> Sylvia Livingston
> Bureau of Air Regulation
> Division of Air Resource Management (DARM)
> 850/921-0771
> sylvia.livingston@dep.state.fl.us
>
> ---
>
> **From:** Bob Fulford [mailto:bobfulford@nettally.com]
> **Sent:** Monday, October 27, 2008 2:19 PM
> **To:** Livingston, Sylvia
> **Subject:** Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC
>
> I have, or thought I had, all versions of the various "acrobats"....one loaded just this morning in fact. I will attempt to load the one you have informed me of.
>
> Meanwhile if you would be so kind as to send a copy by mail that would be very much appreciated.
>
> Thank you.
>
> Bob Fulford
>
>> ----- Original Message -----
>> **From:** Livingston, Sylvia
>> **To:** Bob Fulford
>> **Sent:** Monday, October 27, 2008 12:59 PM
>> **Subject:** RE: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Mr. Fulford,

Do you have Adobe Acrobat installed on your computer? The documents are in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> . Otherwise, I can send this to you by certified mail.

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us

From: Bob Fulford [mailto:bobfulford@nettally.com]
Sent: Monday, October 27, 2008 1:44 PM
To: Livingston, Sylvia
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

I can open this stuff but it is unreadable. Can you send it in another format?

----- Original Message -----
From: Livingston, Sylvia
To: glenn@biggreenenergy.com
Cc: Fancher, Dick ; sosbourn@golder.com ; forney.kathleen@epamail.epa.gov ; Abrams.Heather@epa.gov ; saulsj@leoncountyfl.gov ; proctorb@leoncountyfl.gov ; john.marks@talgov.com ; anita.favors.thompson@talgov.com ; Gibson, Victoria ; gibbyj@earthlink.net ; hopeforcleanwater@yahoo.com ; daswim@gmail.com ; joecain1@comcast.net ; ronsaff@aol.com ; salters@magnet.fsu.edu ; sth@magnet.fsu.edu ; hluebkemann@comcast.net ; shereitte@gmail.com ; richard.gragg@famu.edu ; richardgraggiii@mac.com ; bobfulford@nettally.com ; anitald@embarqmail.com ; susiecaplowe@comcast.net ; dave@no-burn.org ; bradley@greenaction.org ; nseldman@ilsr.org ; dmellman@post.harvard.edu ; ring@tampabay.rr.com ; Linero, Alvaro ; Read, David ; Vielhauer, Trina ; Walker, Elizabeth (AIR)
Sent: Monday, October 27, 2008 11:52 AM
Subject: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Dear Sir/ Madam:
Attached is the official **Notice of Draft Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0730109.001.AC.D_pdf.zip

Additional project information can be found at www.dep.state.fl.us/Air/permitting/construction/tallahassee.htm

Owner/Company Name: BG and E OF TALLAHASSEE, LLC
Facility Name: TALLAHASSEE RENEWABLE ENERGY CENTER
Project Number: 0730109-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION/ Biomass Integrated Gasification and Combined Cycle Unit
Facility County: LEON

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other

Livingston, Sylvia

From: Bob Fulford [bobfulford@nettally.com]
Sent: Monday, October 27, 2008 1:23 PM
To: Livingston, Sylvia
Subject: Read: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Attachments: ATT167130.txt

ATT167130.txt
(268 B)

This is a receipt for the mail you sent to <glenn@biggreenenergy.com> at 10/27/08 11:52 AM

This receipt verifies that the message has been displayed on the recipient's computer at 10/27/08 12:22 PM

Livingston, Sylvia

From: Exchange Administrator
Sent: Monday, October 27, 2008 12:52 PM
To: Livingston, Sylvia
Subject: Delivery Status Notification (Relay)

Attachments: ATT166903.txt; BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

ATT166903.txt (290 B)   BG & E OF .LLAHASSEE, LLC - 1

This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

bobfulford@nettally.com

November 10, 2008

Updated: Leon County's Proctor says "I questioned some issues" involving biomass plant

By Bruce Ritchie
Democrat Staff Writer

Updated1:30 p.m.

Leon County Commissioner Bill Proctor says he isn't pleased with the proposed biomass gas electric plant in Tallahassee as he has stated in his legal challenge requesting an administrative hearing.

"I questioned some issues," he said this afternoon. " I think these issues are substantial enough they need to be heard."

The request appeared to have been filed by an attorney but Proctor declined to say who filed it or discuss the issue in detail.

"I'm looking into it and I can't go there until I actually understand whether the hearing is going to be granted," Proctor said. "I don't want to go further talking about it."
The Democrat has called the Florida Department of Environmental Protection seeking comment. A message also has been left with Glenn Farris, president and CEO of Biomass Gas & Electric, seeking comment.

First update

Leon County Commissioner Bill Proctor has filed a legal challenge to the proposed biomass gas electric plant proposed for Florida State University land off Roberts Avenue.

The Florida Department of Environmental Protection on Oct. 27 said it intends to issue an air emissions permit to Biomass Gas & Electric. The company proposes building a 42-megawatt plant where it will convert heated wood chips into gas that will be burned to produce electricity, which will be sold to city utility customers.

Proctor raised concerns about the plant at an Oct. 28 County Commission meeting. The commission voted to send a letter to DEP asking for more details but Proctor wanted the county to file a legal challenge.

His request for an administrative hearing, filed Friday, said BG&E and DEP have failed to show that pollution control equipment will prevent violations of state and federal air quality standards.

Livingston, Sylvia

From: Farris [glenn@biggreenenergy.com]
Sent: Wednesday, November 05, 2008 12:33 PM
To: Livingston, Sylvia
Subject: Re: FW: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Silvia,
I have opened the documents and saved them to our digital files. Thanks, Glenn Farris President and CEO Biomass Gas & Electric, LLC

---------- Original Message -----------------------------------
From: "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us>
Date: Wed, 5 Nov 2008 12:24:55 -0500

>We have not received confirmation that you were able to access the documents
>attached to this October 27th e-mail, as well as the documents provided in
>the link
>(http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0730109.00
>1.AC.D_pdf.zip) referenced in the email. Please confirm receipt by opening
>the attachment and clicking on the link to the permit documents, and sending
>a reply to me.
>The Division of Air Resource Management is sending electronic versions of
>these documents rather than sending them Return Receipt Requested via the US
>Postal service. Your "receipt confirmation" reply serves the same purpose as
>tracking the receipt of the signed "Return Receipt" card from the US Postal
>Service. Please let me know if you have any questions.
>Thanks,
>
>Sylvia Livingston
>Bureau of Air Regulation
>Division of Air Resource Management (DARM)
>850/921-0771
>sylvia.livingston@dep.state.fl.us
>
>
>>
>
>
>
>The Department of Environmental
>
>Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and
>
>improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of
>
>service you received. Copy the url below to a web browser to complete the DEP
>
>survey: http://survey.dep.state.fl.us/?refemail=Sylvia.Livingston@dep.state.fl.us Thank you in advance for completing the survey.
>
>
>> From: Livingston, Sylvia
>> Sent: Monday, October 27, 2008 12:52 PM
>> To: 'glenn@biggreenenergy.com'
>> Cc: Fancher, Dick; 'sosbourn@golder.com';
>> 'forney.kathleen@epamail.epa.gov'; 'Abrams.Heather@epa.gov';
>> 'saulsj@leoncountyfl.gov'; 'proctorb@leoncountyfl.gov';
>> 'john.marks@talgov.com'; 'anita.favors.thompson@talgov.com'; Gibson,
>> Victoria; 'gibbyj@earthlink.net'; 'hopeforcleanwater@yahoo.com';

Livingston, Sylvia

From: Vielhauer, Trina **Sent:**Thu 11/6/2008 11:52 AM
To: 'susiecaplowe@comcast.net'; Livingston, Sylvia; Walker, Elizabeth (AIR)
Cc: 'hopeforcleanwater@yahoo.com'; Linero, Alvaro
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC
Attachments:

Hi Susie,
For everyone that was copied on our email distribution, you have 14 days from receipt (count that date as day 1) to file a petition for a legal hearing. For those NOT copied on that distribution, they have 14 days from publication of notice to file a petition. That notice published tuesday so the deadline would be 11/17 for those not copied to petition.

Everyone's comment period ends 11/17 (14 days from publication).

Hope that is helpful.

trina
Trina Vielhauer

Sent from my BlackBerry Wireless Handheld

----- Original Message -----
From: susiecaplowe@comcast.net <susiecaplowe@comcast.net>
To: Livingston, Sylvia; Walker, Elizabeth (AIR)
Cc: Vielhauer, Trina; Susie Caplowe <susiecaplowe@comcast.net>; Joy Towles Ezell <hopeforcleanwater@yahoo.com>
Sent: Thu Nov 06 11:20:32 2008
Subject: Re: BG & E OF TALLAHASSEE, LLC - TALLAHASSEE RENEWABLE ENERGY CENTER; 0730109-001-AC

Hi Trina.
Can you please clarify the legal and public comment deadlines for the BGandE bimass plant.
Legal deadline began when?
Public comment began when?
Thank you. Susie
Sent via BlackBerry by AT&T

Tallahassee's Homepage
Tallahassee.com

November 18, 2008

More petitions filed requesting biomass hearing

By Bruce Ritchie
Democrat Staff Writer

At least 11 individuals and couples have filed legal petitions requesting an administrative hearing on a proposed biomass gas electric plant in Tallahassee, according to the Florida Department of Environmental Protection..

Biomass Gas & Electric proposes putting the 42-megawatt plant on Florida State University land between Roberts Avenue and Jackson Bluff Road.

The Florida Department of Environmental Protection announced on Oct. 27 that it intends to issue a permit for the plant.

Leon County Commissioner Bill Proctor was among the first to file a petition last week against the plant. The deadline for those who were on the DEP distribution list was Nov. 10. But for those not on the list, it was Monday.

The Democrat today will request an updated list of the filings from DEP to reflect those filed late in the day on Monday. Check back with Tallahassee.com for an update.

Tallahassee's Homepage
Tallahassee.com

November 18, 2008

Proposed biomass plant in Tallahassee faces concerns

By Bruce Ritchie
Democrat Staff Writer

Erwin Jackson, who owns about 50 homes off Jackson Bluff Road that he rents to college students, said he's going to be out of business if a proposed biomass gas electric plant is built in the area.

Biomass Gas & Electric of Norcross, Ga., proposes building the 42-megawatt power plant on 21 acres of Florida State University land off Roberts Avenue. The company will heat wood chips to produce gas which will be burned to produce electricity, a process that company officials says is environmentally-friendly.

The proposed plant site is within a half-mile of SAIL High School at 2006 Jackson Bluff Road. Erwin Jackson was among about 60 students, parents, teachers and residents who attended a forum last week to discuss the plant.

Jackson argued at the forum that the plant will produce noise, light and odors that will discourage tenants from renting his homes. He said the plant also will affect students and residents in the neighborhood.

"I wouldn't personally want to live 30 feet from this experiment," Jackson said. "We know why you're here. We don't want it."

But company officials say their proposed plant is a green energy solution for Tallahassee and the state. The Florida Department of Environmental Protection has proposed issuing a permit for the plant.

After receiving support early from some city officials and environmentalists in 2006, the proposed plant is facing increasing community opposition.

November 21, 2008

Meeting on biomass plant set for Monday

By Bruce Ritchie
DEMOCRAT STAFF WRITER

Leon County Commissioner Bill Proctor has scheduled a public meeting for Monday to discuss the proposed Biomass Gas & Electric plant in Tallahassee.

The company, from Norcross, Ga., proposes heating plant material to produce gas, which will be burned to produce electricity for city utility customers.

The plant would be built on 21 acres of Florida State University land off Roberts Avenue in southwest Tallahassee.

Proctor along with some south side activists and environmentalists are raising concerns that the plant will cause noise, pollution and odors.

DEP has issued a proposed permit for the plant that it says will protect the environment.

The City Commission on Tuesday is scheduled to consider a development agreement that sets light-industrial zoning standards for noise and light from the property.

BG&E officials say the plant will help make Tallahassee a leader in producing clean, renewable energy. A company spokesman said Thursday representatives cannot attend Proctor's meeting but they will be at the City Commission meeting.

Additional Facts

If you go

What: Proctor meeting on Biomass plant

When: Monday, 6:30 p.m.

Where: Former Amtrak Building, 918 Railroad Ave.

If you go

What: Proctor meeting on Biomass plant

When: Monday, 6:30 p.m.

Where: Former Amtrak Building, 918 Railroad Ave.

Tallahassee's Homepage
Tallahassee.com

November 20, 2008

Updated: Leon County Commissioner Proctor schedules meeting on biomass plant

By Bruce Ritchie
DEMOCRAT STAFF WRITER

11:45 a.m. update

Leon County Commissioner Bill Proctor has scheduled a public meeting for Monday to discuss the proposed Biomass Gas & Electric plant in Tallahassee.

BG&E officials have been invited to attend, according to a statement issued by Proctor.

His meeting is scheduled for 6:30 p.m. at the former Amtrak Building, 918 Railroad Ave.

First update

Eleven petitions have been filed in the past 12 days with the state requesting an administrative hearing on a proposed biomass gas electric plant in Tallahassee.

Biomass Gas & Electric proposes building the plant on 21 acres of Florida State University land off Roberts Avenue.

BG&E would heat plant material to produce gas for a power plant that would provide enough electricity for 24,000 homes.

The Florida Department of Environmental Protection on Oct. 27 said it intends to issue a permit for the plant.

Some of the petitions were filed by residents living in the Jackson Bluff Road area.

They stated the nearby plant poses a health threat and will create noise and odors that will affect their property.

"I hope if enough people find out this is going on, it will be stopped," said community activist Bob Fulford, who lives in the area.

DEP says the plant will use only clean wood material as fuel and will use state-of-the-art pollution control equipment.

The proposed permit will protect the environment, DEP spokeswoman Amy Graham said.

She said the permit addresses odor, but she added that DEP does not deal with noise and other zoning issues.

The City Commission on Tuesday is scheduled to consider a legal agreement that applies light industrial zoning standards for noise and lighting.

BG&E this week filed a petition requesting more time to file its own possible request for a hearing.

The company believes the proposed plant represents the future of sustainable energy and is a great opportunity for the Tallahassee area, said Ryan Banfill of Ron Sachs Communications, which was hired by the BG&E on Wednesday.

Leon County Commissioner Bill Proctor on Nov. 7 was among the first to file a hearing request.

His request, like several of the others, said BG&E and the department have failed to show that pollution control equipment will prevent violations of state and federal air-quality standards.

Seven of the petitions were dropped off at DEP by Gum Road resident John Gibby, DEP spokeswoman Amy Graham said. Gibby also filed a petition Nov.7.

The petitions are being evaluated by the department to determine if they meet legal requirements, Graham said.

Additional Facts

ON THE WEB

DEP's BG&E permit file

Tallahassee Scientific Society

Biomass Gas & Electric

Discussion of Tallahassee BioGas Plant

Floridians Against Incinerators in Disguise Yahoo! group

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

ANDRES RODRIGUEZ, M.D,
PRESIDENT
CAPITAL MEDICAL SOCIETY
1204 MICCOSUKEE ROAD
TALLAHASSEE, FL 32308

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Jore Chapman
☐ Agent
☐ Addressee

B. Received by (Printed Name)

C. Date of Delivery
10-28

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

CENTERVILLE STATION TALLAHASSEE FL 32308
OCT 28 2008
USPS

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7005 1160 0004 3034 5735

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

JOHN GIBBY
4887 GUM ROAD
TALLAHASSEE, FL 32304

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X John Gibby
☐ Agent
☐ Addressee

B. Received by (Printed Name)
John Gibby

C. Date of Delivery
Oct 30, 2008

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7005 1160 0004 3034 5742

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Bob Fulford
231 Westridge Dr.
Tallahassee, FL 32304

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [illegible]
☐ Agent
☐ Addressee

B. Received by (Printed Name)
R A FULFORD

C. Date of Delivery
10/29/8

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7005 1160 0004 3034 5759

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

7005 1160 0004 3034 5735

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Postage	$
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Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To Andres Rodriguez
Street, Apt. No.; or PO Box No. 1204 miccosukee rd
City, State, ZIP+4 Tallahassee, Fl 32308

PS Form 3800, June 2002 See Reverse for Instructions

7005 1160 0004 3034 5742

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OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$.

Postmark Here

Sent To John Gibby
Street, Apt. No.; or PO Box No. 4887 Gum Road
City, State, ZIP+4 Tallahassee Fl. 32304

PS Form 3800, June 2002 See Reverse for Instructions

7005 1160 0004 3034 5759

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(Domestic Mail Only; No Insurance Coverage Provided)

For delivery information visit our website at www.usps.com®

OFFICIAL USE

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Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To Bob Fulford
Street, Apt. No.; or PO Box No. 231 Westridge Dr.
City, State, ZIP+4 Tallahassee Fl. 32304

PS Form 3800, June 2002 See Reverse for Instructions

Livingston, Sylvia

From: John Gibby [gibbyj@earthlink.net]
Sent: Thursday, October 30, 2008 7:20 PM
To: Vielhauer, Trina; McGuire, Chris; Tedder, Richard; Linero, Alvaro
Cc: Joyal, Francine; Livingston, Sylvia; Read, David
Subject: administrative hearing data Re: Solid Waste _Fw: BG&E Biomass Permit

October 30, 2008

Trina Vielhauer
Florida Department of Environmental Protection
Chief, Bureau of Air Regulation

Dear Ms. Vielhauer,

Thank you for your response October 30, 2008.

Ms. Joyal did respond to my questions as of October 30, 2008. I am most satisfied with her response.

However, I need an official response from the **Florida Department of Environmental Protection** staff by certified mail responding to my question(see below).

Let me help you understand the reason for the official response.

I am preparing a petition for an administrative hearing in accordance with sections 120.569 and 120.57, F.S. for **DEP File NO. 0730109-001-AC, Biomass Gas and Electric**.

I need the "official" response to help explain how my substantial interests will be affected by the agency determination and support my concise statement of the ultimate facts alleged warrant reversal or modification of the proposed action.

The Question:

Per **Florida Department of Environmental Protection**, is/are the following considered a Solid Waste/Yard Waste/Municipal Solid Waste?

BG&E WOODY BIOMASS FEEDSTOCK PROPERTIES:
Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to woody biomass meaning trees and woody plants, including limbs, tops, trunks, needless, leaves, stalks and other woody parts, grown in a forest, woodland, rangeland environment, tree farm or agricultural crop farm. The term includes such materials generated in conjunction with the safe transmission power line management practices of the City of Tallahassee. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass including sander dust, wood chips, saw dust and bark.

Please note that that I have only 10(TEN) days left to respond.

John Gibby
4887 Gum Road
Tallahassee, FL

32304

CC:
Division of Waste Management #850-245-8705 MS #4500
2600 Blair Stone Road, Tallahassee, Florida 32399-2400

Richard Tedder, Solid Waste Section
Chris McGuire, Office of General Counsel

----- Original Message -----
From: Vielhauer, Trina
To: Livingston, Sylvia
Cc: gibbyj@earthlink.net
Sent: Thursday, October 30, 2008 7:59 AM
Subject: RE: Solid Waste _Fw: BG&E Biomass Permit

Thank you, Sylvia.

Mr. Gibby,
I believe after I received this, you received a response from Ms. Joyal in our Division of Waste Management. I am attaching that response here. If I am misstaken and you are still awaiting a response, please let me know.

Sincerely,

Trina Vielhauer

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

From: Livingston, Sylvia
Sent: Wednesday, October 29, 2008 9:50 AM
To: Vielhauer, Trina
Cc: 'gibbyj@earthlink.net'
Subject: FW: Solid Waste _Fw: BG&E Biomass Permit

Trina,

Mr. Gibby asked me to forward this email to you.

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us

From: John Gibby [mailto:]
Sent: Tuesday, October 28, 2008 9:17 PM
To: McGuire, Chris; Tedder, Richard; Livingston, Sylvia
Cc: Joyal, Francine; Read, David; Linero, Alvaro
Subject: Solid Waste _Fw: BG&E Biomass Permit

October 28, 2008

To: Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us
Dear Ms Livingston:
Will you please forward this email to:

Trina Vielhauer, Chief Bureau of Air Regulation.(I do not have e-mail address)

Thanks.

John Gibby

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October 28, 2008

To: Trina Vielhauer, Chief Bureau of Air Regulation

Dear Ms. Vielhauer,

This is my forth request for the below information from the Solid Waste section.

Can you help with obtaining the response from Mr. Tedder.

The response is important to the BG&E permit(Air).

The public has only DAYS to respond to the FDEP Draft Permit(BG&E).

Please help the public make an informed decision by helping to provide the answer(s) to my question(s) from the Solid Waste section.

As you know the public has only 14 (fourteen) days to respond.

Thank you

John Gibby

----- Original Message -----
From: John Gibby
To: McGuire, Chris ; Tedder, Richard
Cc: Johnson, John S. ; Joyal, Francine ; Linero, Alvaro ; Read, David
Sent: Tuesday, October 28, 2008 1:41 PM
Subject: BG&E Biomass Permit

October 28, 2008

To: Florida Department of Environmental Protection

Division of Waste Management #850-245-8705 MS #4500
2600 Blair Stone Road, Tallahassee, Florida 32399-2400

Richard Tedder, Solid Waste Section
Chris McGuire, Office of General Counsel
Dear Mr Tedder:
Per 62-701.200 Definitions, is/are the following considered a Solid Waste?

BG&E WOODY BIOMASS FEEDSTOCK PROPERTIES:

Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to woody biomass meaning trees and woody plants, including limbs, tops, trunks, needless, leaves, stalks and other woody parts, grown in a forest, woodland, rangeland environment, tree farm or agricultural crop farm. The term includes such materials generated in conjunction with the safe transmission power line management practices of the City of Tallahassee. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass including sander dust, wood chips, saw dust and bark.

Your timely response is requested.

John Gibby
4887 Gum Road
Tallahassee, FL
32304

CC:
Alvaro Linero, Program Administrator (Air)
850-921-9523