Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer

THROUGH: Al Linero *aal*

FROM: Teresa Heron

DATE: January 26, 2010

SUBJECT: DEP File No. 0450012-001-AC
Northwest Florida Renewable Energy Center
Biomass Integrated Gasification Combined Cycle Unit

Attached for your review a is the Draft Air Construction Permit package for the Northwest Florida Renewable Energy Center that will be located in Gulf County at 521 Premier Drive in Port St. Joe, Florida.

This project is not subject to the rules for the Prevention of Significant Deterioration. We recommend your approval of the attached draft permit package.

Attachments

TLV/aal/tmh

PROFESSIONAL ENGINEER CERTIFICATION STATEMENT

Permittee:
Northwest Florida Renewable Energy Center, LLC
11993 South Street, Route 63
Clinton, Indiana 47842

DEP File No. 0450012-001-AC
Northwest Florida Renewable Energy Center
Biomass Integrated Gasification Combined Cycle
Gulf County, Florida

Project: To construct the Northwest Florida Renewable Energy Center consisting of a 47 megawatts (MWnet) biomass integrated gasification combined cycle unit and ancillary equipment. The project will be located in Port St. Joe, Gulf County, Florida. Details of the project are provided in the application available at:

www.dep.state.fl.us/Air/emission/construction/stjoe.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 (BACT) 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. 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.*

1/26/2010

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

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

Electronically Sent – Received Receipt Requested.

kdavis@whiteconstruction.com
Mr. Kenn Davis, Manager
Northwest Florida Renewable Energy Center, LLC
P.O. Box 249, 11993 South St. Rt. 63
Clinton, Indiana 47842

Re: DEP File No. 0450012-001-AC
Northwest Florida Renewable Energy Center
Biomass Integrated Gasification and Combined Cycle Unit

Dear Mr. Davis:

On September 2, 2009, you submitted an application for an air construction permit subject to the preconstruction review requirements of Rule 62-212.300, Florida Administrative Code.

The purpose of the project is to construct a 47 megawatt (MWnet) biomass-fed integrated gasification and combined cycle unit called Northwest Florida Renewable Energy Center to be located in Gulf County at 521 Premier Drive in Port St. Joe, Florida.

Enclosed are the following documents: Written Notice of Intent to Issue Air Permit; Public Notice of Intent to Issue Air Permit; Technical Evaluation and Preliminary Determination; and a Draft Permit with Appendices.

The Public Notice of Intent to Issue Air 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 or Teresa Heron the project engineer at (850) 921-9529.

Sincerely,

Trina L Vielhauer 1/27/10

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

TLV/aal/tmh

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Mr. Kenn Davis, Manager
Northwest Florida Renewable Energy Center, LLC
11993 South Street, Route 63
Clinton, Indiana 47842

DEP File No. 0450012-001-AC
Northwest Florida Renewable Energy Center
Biomass Integrated Gasification Combined Cycle Unit
Gulf County, Florida

Facility Location: The proposed Northwest Florida Renewable Energy Center will be located at 521 Premier Drive in Port St. Joe, Gulf County, Florida.

Project: The project is the construction of a 47 megawatts (MWnet) biomass integrated gasification combined cycle unit and ancillary equipment. A review pursuant to the rules for Prevention of Significant Deterioration (PSD) and a determination of best available control technology (BACT) pursuant to Rule 62-212.400, F.A.C. were not required.

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 air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Bureau of Air Regulation's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation'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.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air 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 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 the 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, Mail Station #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 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 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 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 Vielhauer 1/28/10
Trina Vielhauer (Date)
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 Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on 1/28/10 to the persons listed below.

Kenn Davis, NWFREC: kdavis@whiteconstruction.com
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
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Richard Gragg III: richardgraggiii@mac.com
Bob Fulford, Citizen: bobfulford@nettally.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
Dr. Bill Sammons: drsammons@aol.com

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) 1/28/10 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
DEP File No. 0450012-001-AC
Northwest Florida Renewable Energy Center
Biomass Integrated Gasification Combined Cycle Unit
Gulf County

Applicant: The applicant for this project is Northwest Florida Renewable Energy Center, LLC. The applicant's authorized representative and mailing address is: Mr. Kenn Davis, Manager, 11993 South Street Route 63, Clinton, Indiana 47842.

Facility Location: The proposed Northwest Florida Renewable Energy Center (NWFREC) will be located at 521 Premier Drive in Port St. Joe, Gulf County, Florida.

Project: The project is to construct the NWFREC, which will be a 47 megawatts (MWnet) biomass integrated gasification combined cycle unit and ancillary equipment. 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 and untreated wood materials. Municipal solid waste (MSW) is expressly prohibited as a fuel source for the NWFREC.

The woody biomass will be dried and fed into a vessel containing a heated bed of circulating sand where the woody biomass will be converted to biomass product gas (BPG). The BPG will be cleaned, compressed and used as fuel in two 16 MW (gross) combustion turbine-electrical generators (CTG). Heat from the CTG exhaust gas will be recovered in two heat recovery steam generators (HRSG) equipped with BPG-fueled duct burners (DB). The resulting steam from the HRSG will drive a single 26.2 MW (gross) steam turbine-electrical generator (STG). The parasitic electrical loads at the facility are estimated to be 11.3 MW resulting in an electrical power output of 47 MWnet that can be supplied to the power grid.

The project will result in emissions increases of: 142 tons per year (TPY) of carbon monoxide (CO); 165 TPY of nitrogen oxides (NO_X); 47.4 TPY of particulate matter (PM); 41.4 TPY of PM with a mean diameter of 10 micrometers (μm) or less (PM_{10}); less than 7 TPY of sulfuric acid mist (SAM); 29.9 TPY of sulfur dioxide (SO_2); 24 TPY of volatile organic compounds (VOC); negligible amounts of lead (Pb) and mercury (Hg); and 5 TPY of other hazardous air pollutants (HAP). Because the potential emissions are below the major source thresholds, a review for the Prevention of Significant Deterioration (PSD) and a best available control technology (BACT) determination were not required.

To insure that emissions are less than the respective major source thresholds for PSD and hazardous air pollutants (HAP) and that compliance is achieved with applicable new source performance standards, the Department requires installation and operation of the following air pollution control equipment and practices at the facility: fabric filters and good combustion design and practices (PM, PM_{10}, CO, VOC); oxidation catalyst and selective catalytic reduction within the HRSG (NO_X, VOC, CO and dioxin/furan); and inherently low sulfur fuels (SO_2). In addition, 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 Department will require that continuous emissions monitoring systems (CEMS) be installed for NO_X and CO and that fuel analysis be conducted to limit SO_2 and sulfuric acid mist (SAM) emissions. Emissions from emergency support equipment will be controlled by use of clean fuels and good combustion and design. Reasonable precautions will be employed to minimize fugitive dust emissions from biomass handling, storage and processing.

The Department reviewed an air quality analysis prepared by the applicant. The analysis demonstrated that ground-level concentrations of nitrogen dioxide (NO_2), PM_{10}, CO and SO_2 caused by the project, including background concentrations, will be much less than the respective National or Florida ambient air quality standards (AAQS).

The Technical Evaluation and Preliminary Determination document and the air quality analysis are available at the following web link:

www.dep.state.fl.us/Air/emission/construction/stjoe.NWFRECTech.pdf

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 air permitting requirements and an air permit is required to perform the proposed work. The Permitting Authority responsible for making a permit determination for this project is the Bureau of Air Regulation in the Department of Environmental Protection's Division of Air Resource Management. The Bureau of Air Regulation's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Bureau of Air Regulation's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation'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 the physical address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application and information submitted by the applicant (exclusive of confidential records under Section 403.111, F.S.). Interested persons may contact the Permitting Authority's project engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available on the following web site:

www.dep.state.fl.us/Air/emission/construction/stjoe.htm

Notice of Intent to Issue Air 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 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.

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 this 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 the 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 at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241). 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 rights will be affected by the agency determination; (c) A statement of when and how the 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 of Intent to Issue Air 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 for this proceeding.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Northwest Florida Renewable Energy Center, LLC

47-Megawatt (net) Biomass Integrated Gasification Combined Cycle

Gulf County

DEP File No. 0450012-001-AC

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

January 27, 2010

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Northwest Florida Renewable Energy Center, LLC
11993 South Street, Route 63
Clinton, Indiana 47842

***Authorized Representative*:** Mr. Kenn Davis, Manager

1.2. Processing Schedule

September 2, 2009:	Received air construction permit application from North West Florida Renewable Energy Center, LLC.
October 2, 2009:	Sent request for additional information (RAI) to the Applicant.
October 14, 2009:	Held public meeting regarding application.
November 4, 2009:	Received response to RAI.
January 27, 2010:	Intent to Issue PSD Permit distributed.

1.3. Facility Location

The proposed Northwest Florida Renewable Energy Center (NWFREC) will be located in Port St. Joe, Gulf County, Florida. The proposed project location is approximately 1.6 miles directly north of the intersection of US Highway 98 and Highway 71, off of Industrial Road at 521 Premier Drive in Port St. Joe, Gulf County. The approximate UTM coordinates for this site are Zone 16; 664.16 kilometers (km) East and 3,301.96 km North. The location of the proposed NWFREC is shown in Figure 1.

Figure 1. Project Location in Port St. Joe.

Figure 2. Artist Rendition of Future NWFREC.

Figure 2 is an artist rendition of the proposed facility. Initially biomass will be delivered by trucks and not by railroad. The site is located approximately 75 km from the nearest boundary of the St. Marks National Wildlife Refuge and also 75 km from the nearest boundary of the Bradwell Bay National Wilderness Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Areas.

1.4. Regulatory Categories

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.

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The facility is not a major source of hazardous air pollutants (HAP) because it will not have the potential to emit (PTE) 10 tons per year (TPY) of any single HAP or 25 TPY of all HAP.

Title IV, Acid Rain Provisions

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

Title V, 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).

Clean Air Interstate Rule (CAIR)

The facility is subject to CAIR in accordance with the Final Department Rules in Rule 62-296.470, F.A.C.

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.

2. PROPOSED PROJECT SUMMARY

2.1. Project Description

The applicant proposes to construct a nominal 47 MW (net) biomass integrated gasification combined cycle (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 (CTG); two supplementary-fired heat recovery steam generators (HRSG) equipped with duct burners (DB); a steam turbine-electrical generator (STG); CTG/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;
- Catalytic destruction of pollutants from the CTG; and,
- Cooling of steam turbine condensate and compressor gas.

2.2. Additional Project Features

Fuel

Municipal Solid Waste (MSW) is prohibited as a fuel at this facility. The NWFREC will generate electricity from BPG, char and tar derived on-site from woody biomass. Natural gas, biodiesel or ultralow sulfur distillate fuel oil (ULSD FO) will be used primarily as a startup fuel.

Generating Capacity

The BIGCC will have a nominal electrical generating capacity of 47 MW (net), 58.2 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 pounds (lb). The heat input from the char combustor to the system will be approximately 153 million Btu per hour (mmBtu/hr) or about 25 percent of the total heat input.

Air Pollution Controls – BPG Combustion in CTG 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 CTG 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; water injection into the combustors; and by selective catalytic reduction

(SCR) in the HRSG following combustion.

- HCl is also removed in the scrubber water.
- CO and VOC will be controlled by high temperature combustion and an oxidation catalyst system.
- 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 CTG; and further oxidation by SCR in the HRSG after combustion in the CTG 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 CTG/HRSG sets, inclusive of the DB and while firing BPG:

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

BPG Heat Input Rate to CTG, DB Lower Heating Value (LHV)		Compressor Inlet Temp., °F	Stack Exhaust Temp., °F	Stack Exhaust Flow lb per hour (lb/hr)
CTG	161 mmBtu/hr	59 °F		
DB	71.2 mmBtu/hr			
Total	232.2 mmBtu/hr		352°F	421,390

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 (CTG/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 clean woody biomass that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. NWFREC has identified the possible, available feedstock types listed in Table 2 for their facility. Materials not on the list cannot be used as fuel without prior approval of the Department.

Woody biomass consists of cellulose, hemicellulose, lignin and minerals. NWFREC submitted fuel analyses for biomass of the kind they intend to use at their energy center facility. The key values are given in Table 3. The actual fuels approved for use are identified in the Best Management Practices (BMP) Plan included in the appendices to the draft permit. A similar analysis for a typical Eastern Kentucky (E. KY) bituminous coal is presented for comparison.

Table 2. Summary of Woody Biomass Fuel Descriptions.

Fuel Group	Description
Saw Dust	Saw dust and kerf waste from cutting/milling whole green trees
Hogged Fuel	Land clearing debris that has either been processed, run to a tub grinder, or a horizontal mill at a specific private forest clearing site.
Processed Butt Cuts	Round wood residues that are either of oversized or undersized non processible untreated materials from post or pole manufacturers.
Fuel (vegetative) Crop	A vegetative product specifically grown for energy use or a waste product of agricultural operations (e.g., corn stover, peanut hulls, etc.)

Table 3. Analyses of Candidate Biomass Feedstock Compared with Bituminous Coal.

Parameter	Saw Dust	GP Fuel [1]	Hogged Fuel	Butt Cuts	Crop Fuels	E. KY Coal
Proximate Analysis (dry)						
Moisture (%)	59.68	36.14	34.54	31.52	23.35	2.38
Ash (%)	3.12	1.80	1.67	0.48	3.80	12.27
Calorific Value (Btu/lb)	8,458	9,061	8,254	8,336	8,070	12,900
Volatile Matter (%)	78.15	75.15	79.37	83.25	75.75	35.79
Fixed Carbon (%)	18.73	23.05	18.96	16.27	20.34	51.94
Ultimate Analysis (dry)						
Sulfur (%)	0.02	0.06	0.03	0.01	0.11	1.52
Carbon (%)	50.11	55.38	47.20	51.65	47.37	73.17
Hydrogen (%)	6.01	6.51	5.56	6.10	5.73	5.01
Nitrogen (%)	0.26	0.27	0.34	0.19	0.44	1.62
Oxygen (%)	40.48	35.98	45.20	41.57	42.50	6.41
Fluorine (ppmw)	<10	<10	<10	<10	---	30
Chlorine (%)	0.02	0.02	0.02	0.03	0.00	0.10
Mercury (ppmw)	<0.02	<0.02	0.03	<0.02	---	0.15

1. Georgia Pacific (GP) Fuel is reject material from round wood debarking at an oriented strand board plant.

In general, the key differences between the biomass examples 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.

3.3. Fuel Receiving and Handling

Biomass Stackout

All woody biomass will be delivered to the site via truck at a rate of approximately 45 trucks per day. The fuel storage pile will contain 10 to 14 days of fuel storage.

The truck receiving system will be equipped with two 75-foot platforms dumping into two 5,000-cubic foot receiving hoppers. The hoppers will have a very slow moving chain drag to minimize dust. The hoppers will have a discharge rate capability of 150 tons per hour (TPH).

Tramp metal will be removed using a suspended self-cleaning magnet from the material stream prior to stockpiling the fuel. From the bottom of the two collection hoppers, the wood chips will be discharged onto a take-away belt conveyor. Material will discharge from the take-away conveyor into a horizontal scalping screen. Any oversized materials will be directed to a vertical hammer hog designed to produce 2-inch minus material.

The hog and ancillary conveyors will be supported in a common tower with applicable chute work and dust collection with baghouse. Material will discharge from the hog onto a covered collection conveyor and then transition to the circular stacker.

The circular stacker will form a circular kidney shaped pile at a rate of 300 TPH. The collection conveyor will deliver material to a fully automated stockpile. The stacker will be capable of automatically building a circular stockpile. The feedstock will be evenly distributed in piles up to an average of 40 feet high. The stockpile will have a storage capacity of 2 million cubic feet. The stacker reclaimer will include on-board controls and the stacker reclaimer will be designed to meet operational and structural specifications.

The main storage pile will be built and managed to the extent feasible on the principle of first-in/first-out. A similar configuration is shown in Figure 3.

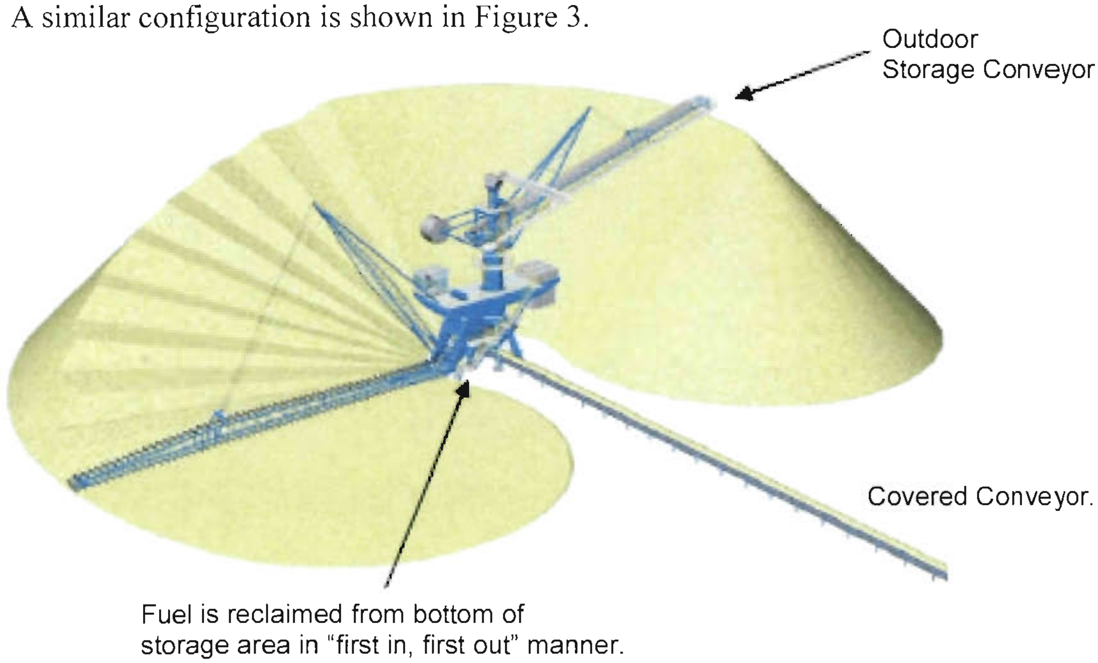

Figure 3. Layout of Kidney-Shaped Pile Operating on Principle of First In/First Out.

The purpose is to allow good chip blending, high stacking and reclaiming, low chip damage, and low operation costs. Such piles are fairly resistant to high winds. By practicing first-in/first-out, such operation will minimize dust generation, biological degradation and odors.

Biomass Reclaim

Biomass will be reclaimed via a stacker from the storage pile via a drag chain to covered Reclaim Conveyor No. 1. This conveyor will transfer the material to covered Reclaim Conveyor No. 2 and from Reclaim Conveyor No. 2 the biomass will be transported to Supply Conveyor No. 3, which is controlled by a baghouse.

Prior to entering the powerhouse the fuel will be conveyed via Supply Conveyor No. 3 to a dryer where the moisture is reduced from as high as 45 percent (%) to approximately 23% by contact with preheated air, as shown in Figure 4 below.

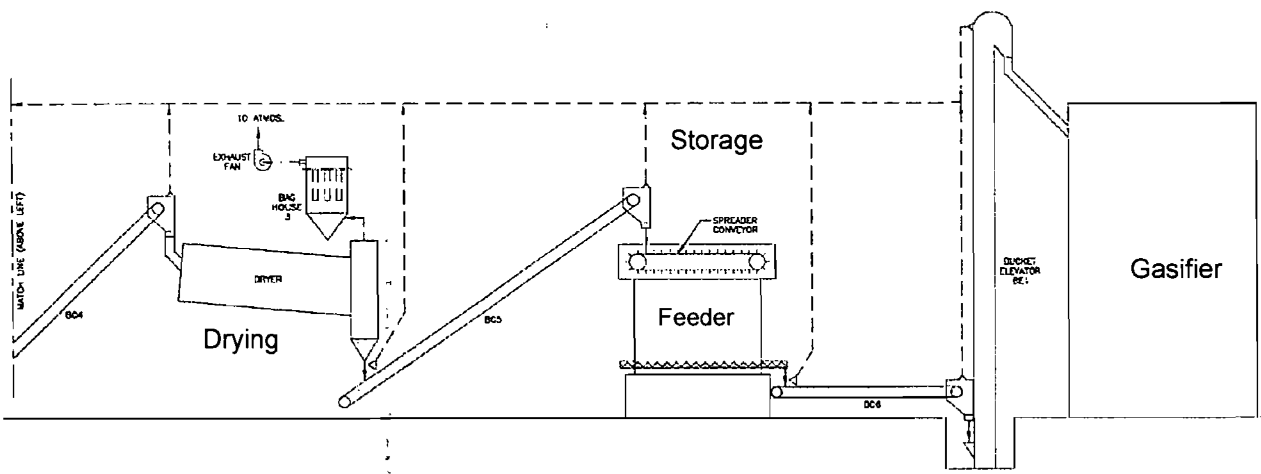

Figure 4. Woody Biomass Drying, Conveyance and Feeding to Gasifier.

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 900 dry tons per day (TPD) of biomass (maximum 1,000 dry TPD) will be fed to the gasifier.

All transfer systems from conveyor to conveyor employ head boxes, chutes, and skirtboard systems enclosed to the degree practicable to contain the fuel and any dust that may be produced at the transfer points. Particulate emissions from these transfer points are kept to a minimum through special designs. The feed bin has a bin vent on top of it to filter the air displaced by transfer of wood into the metering bin.

In addition, all conveyors will be covered to reduce particulate matter emissions. A baghouse will control emissions from the day bin and from transfer of material from the day bin to the bucket elevator.

3.4. 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) CTG.

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.

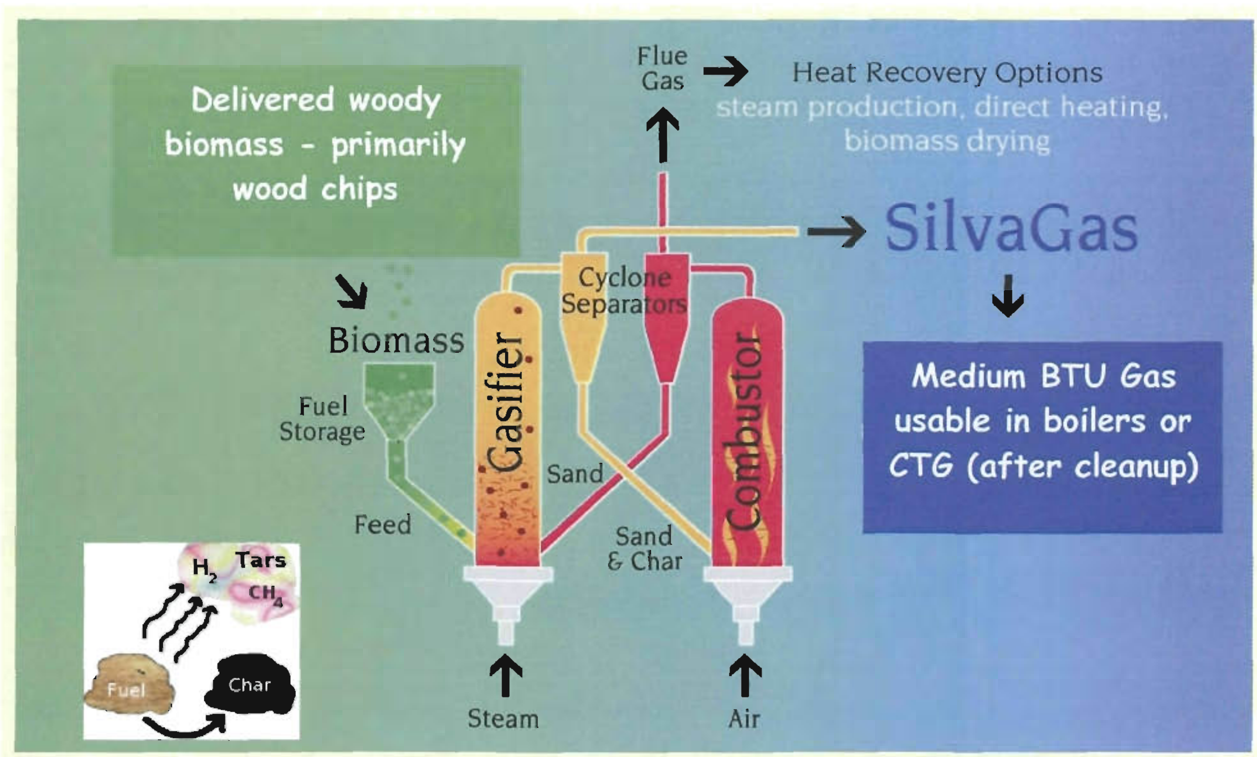

Figure 5. Gasifier/Combustor Section of the SilvaGas Process and Exhaust streams.

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 CTG 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 CTG and DB. The char and cooled sand are separated from the BPG exiting the gasifier in dual, two-stage gasifier cyclones. The sand, char and tars (returned from downstream BPG cleaning) are then fed to the combustor. Air is introduced at the bottom of the vessel and supports conventional combustion of the char and tars in a CFB of sand and an oxidizing atmosphere at approximately 1615 °F.

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

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

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

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 in Figure 6 were taken from the article.

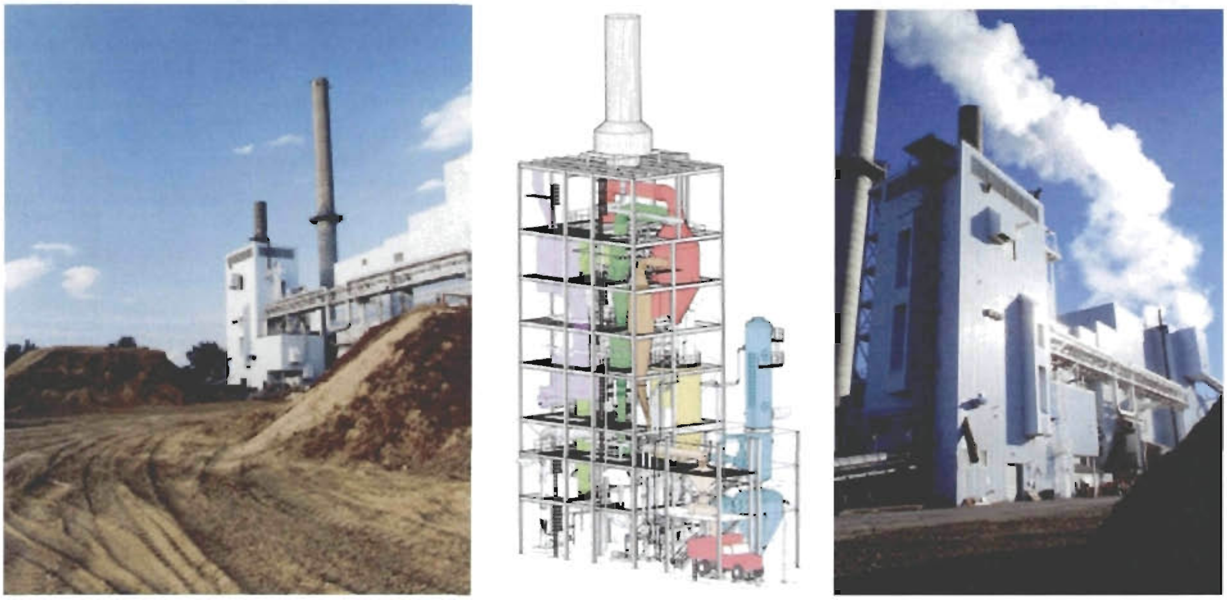

Figure 6. External Views and Internal Diagram of Gasifier/Combustor at McNeil Station.

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 Battelle.[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 CTG such as proposed for the NWFREC. Operation of the gasification system was discontinued at the McNeil Station - for economic reasons. BED continues to operate the McNeil Station as a conventional wood-fueled power plant.

3.5. Char Combustor Exhaust Gas Cleanup

An overall process diagram provided by NWFREC for the proposed energy center including the gasifier, char combustor, cleanup systems and CTG is reproduced in Figure 7.

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 CTG.

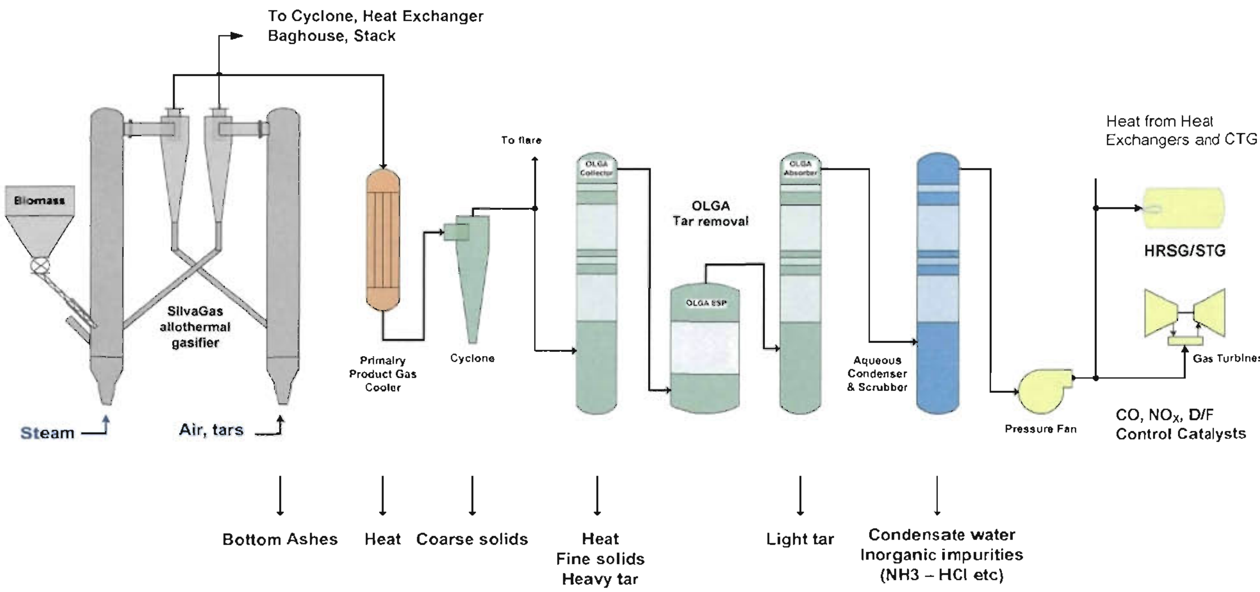

Figure 7. SilvaGas Gasifier/Combustor, NWFREC Cleanup System and Power Generation.

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. 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.

3.6. 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 CTG.

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 CTG. 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 8 on the left hand side. 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.

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

According to NWFREC, LLC, 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 Figure 9 shows the OLGA system at the Moisannes location. The photograph on the right is of a physical model of an OLGA system.

3.7. BPG Scrubbing

Before combusting the BPG in the CTG 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 will likely remove some Hg.

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

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 the applicant, 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 CTG trains.

3.8. BPG and Natural Gas Firing in CTG

BPG Delivered for Combustion

Cooled, sweetened, cleaned BPG is compressed in a pair of two-step BPG compressors and delivered to the CTG. The characteristics of the BPG are given in Table 4. The cleaned BPG can be described as medium heating value fuel.

Table 4. Typical BPG Composition from Silva Gas Process.

Constituent	Product Gas Composition (% by Volume)
Hydrogen (H_2)	20.7
Carbon Monoxide (CO)	45.8
Methane (CH_4)	15.61
Carbon Dioxide (CO_2)	11.03
Ethylene (C_2H_4)	5.26
Ethane (C_2H_6)	0.68
Water (H_2O)	0.22
Nitrogen (N_2)	0.68
Hydrogen Sulfide H_2S	0.02
LHV (Btu/standard ft^3)	435

Description of CTG

BPG will be fired in each CTG. Natural gas, ULSD FO or biodiesel will be used as startup fuels. A CTG 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 16 MW SOLAR T-130 CTG. Each CTG will have a maximum heat input of 161 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 CTG.

How the CTG 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.

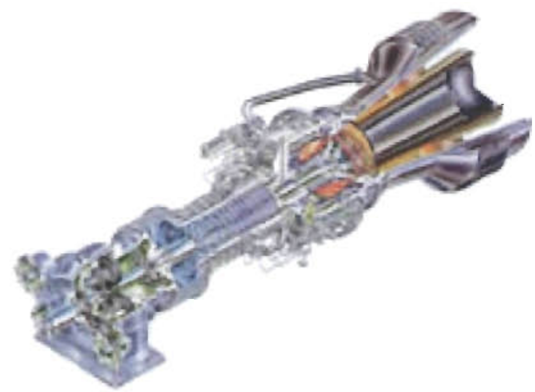

Figure 10. Gas-Fired Unit with T-130 CTG. Diagram of Compressor and Rotor Sections.

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 CTG is on the order of 35% 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 CTG compressor inlet air. The practice reduces the compressor inlet air temperature and, in turn, results in greater mass flow rate through the CTG 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 71 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 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.

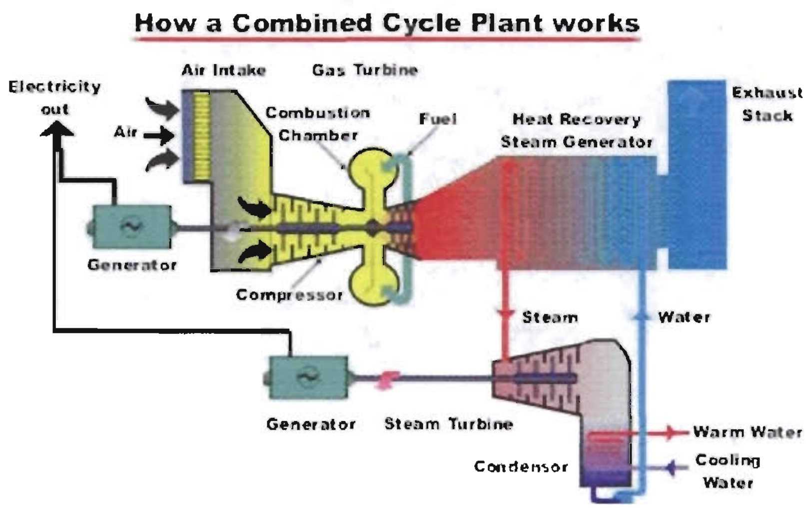

Figure 11. A conventional natural gas fueled combined cycle unit.

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 NWFREC 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 NWFREC 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 5 summarizes the applicant's estimates of key pollutants including those from the CTG, DB, char combustor, flares, material handling, an auxiliary boiler and cooling towers.

Table 5. Applicant's estimate of annual emissions from the NWFREC in TPY.

Pollutant	CTG/DB	Char Combustor	Cooling Towers	Material Handling	Aux. Boiler	Flares	Dryer	Total
SO_2	7.9	13.1	0	0	0.09	0.05	0	21.1
PM	22.8	2.5	1.03	12.4	0.03	Neg	0.10	38.9
PM_{10}	22.8	2.5	0.73	6.78	0.03	Neg	0.01	32.9
NO_X	120	41.7	0	0	1.47	1.58	0	164.8
CO	110.4	13.9	0	0	1.24	8.59	0	134.1
VOC	13.7	6.9	0	0	0.08	3.25	0	24
SAM	<4	<3	0	0	Neg	Neg	0	<7
HAP	4	1	Negligible (Neg)					5
Hg	Neg	6 lb/yr	Neg					6 lb/yr
NH_3	23	Emissions from CTG/DB are "slip" from SCR. Rest assumed neg.						23
Fluoride (F)	Neg							~0
Lead (Pb)	Neg							~0

No PSD pollutant emissions will equal or exceed 250 TPY, based on operation design and associated emission limits. Therefore, the NWFREC 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.

4.4. <u>New Source Performance Standards and National Emissions Standards for HAP</u>

The CTG 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 CTG that will be used at the NWFREC (> 50 mmBtu/hr and ≤ 850 mmBtu/hr) are given in the following table and also account for DB emissions.

Table 6. Emission standards applicable to NWFREC based on 40 CFR 60, Subpart KKKK.

New CTG 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 NWFREC.

Subpart KKKK will be the primary basis for the permit conditions related to the CTG 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 14.9 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 (CTG/DB) stack to approximately 13.7 pounds per hour (lb NO_X/hr) and to 120 TPY from the two HRSG stacks combined.

Because the NWFREC 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 NWFREC were a major source of HAP, the applicability of Subpart YYYY has been stayed for lean premix and diffusion flame gas-fired CTG 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 is applicable and concludes (based on previous informal consultations with various offices of EPA about an identical project) they do not apply to the NWFREC:

- 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.

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 NWFREC:

- 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 CTG 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 CTG combustor as seen on the left hand side of Figure 12.

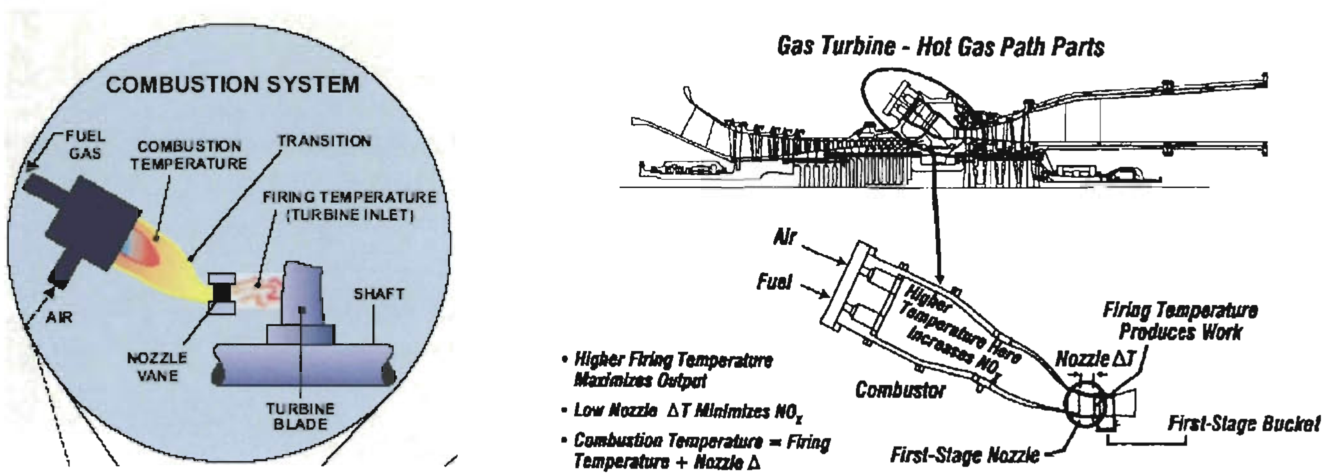

Figure 12. Relation between Combustion and Firing Temperatures and NO_X Formation.

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 CTG 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.

BPG is mostly hydrogen and CO and will combust with a high flame temperature on the order of 4,300 °F in the SOLAR T-130 CTG. The applicant estimates pre-control emissions at approximately 325 ppmvd @15% O_2 from the CTG 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 CTG 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 $SoLoNO_X$. According to SOLAR, this technology is not available for this application because the heating value (actually the Wobbe Index) of the BPG is not within the range that supports lean premix combustion.

According to SOLAR, despite the low heating value, BPG burns hot enough to allow a moderate level of water injection into the combustors to reduce NO_X emissions prior to addition polishing by add-on control equipment.

In addition to water injection, 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.

Given water injection and SCR, the Department has reasonable assurance that the NWFREC project can achieve the reduction from 325 ppmvd @15% O_2 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 14.9 ppmvd that will also provide reasonable assurance that the PTE NO_X from the facility will be less than 250 TPY of NO_X. For convenience in reporting, the limit will be established at 15.0 ppmvd@15% O_2.

Figure 13 (from 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 NWFRC. 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.

The low NO_X formation potential of the char combustor (due to relatively low char nitrogen and low firing temperature) was previously above. In contrast to the CTG/DB, additional NO_X controls are not needed. The applicant estimated NO_X emissions from the char combustor at 41.7 TPY (approximately equal to 9.5 lb/hr).

The Department will require annual testing of the char combustor to provide further assurance and to verify that (in conjunction with emissions from the CTG/DB) the facility-wide emissions of NO_X will be less than 250 TPY.

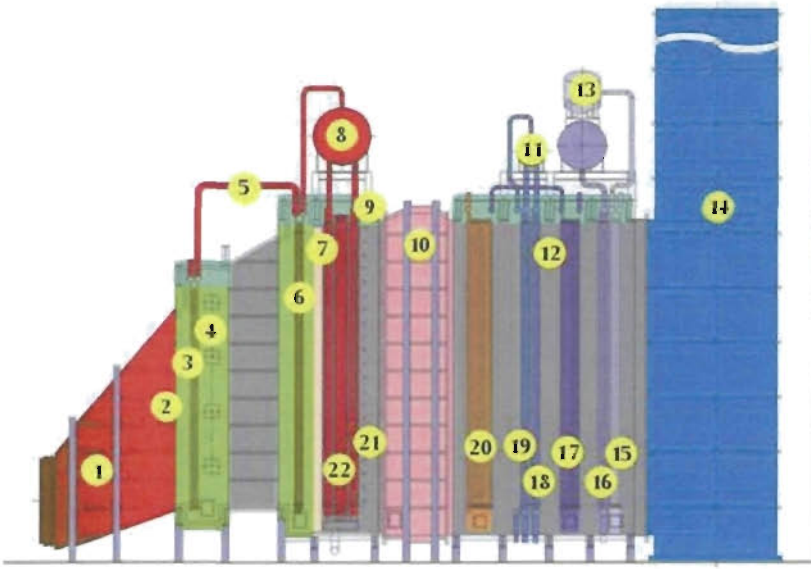

Figure 13 – Key HRSG Components (10 is SCR).

Figure 14 – PEF Hines Block I.

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

The main control for SO_2 for the NWFREC 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 clean up process 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 CTG 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 O_2, temperature, 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 estimated that prior to clean up, the concentration of H_2S in the BPG will be 0.02%. The emissions from burning cleaned BPG in the CTG will be 0.90 lb SO_2/hr from each HRSG. This equates to emissions of 0.002 lb SO_2/mmBtu and is much less than the limit of 0.060 lb SO_2/mmBtu required by Subpart KKKK.

Compliance with a fuel sulfur based on the pre-control H_2S concentration of 0.02% S in the BPG will be sufficient to demonstrate compliance with the Subpart KKKK limit of 0.060 SO_2 lb/mmBtu with an ample margin of safety. It is also sufficient to insure that the facility will not be a major stationary source of SO_2.

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 NWFREC.

Emissions from the CTG 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.

Table 7 is a summary of CO and VOC emissions estimated by the applicant from the CTG/HRSG stacks after control and including emissions from the char combustor.

Table 7. Projected CO and VOC from HRSG (CTG/DB) and Char Combustor at NWFREC.

Location	Mass Rate (lb/hr)		Annual Emissions (TPY)	
	CO	VOC	CO	VOC
Each HRSG stack	12.6	1.6	55.2	6.85
Two HRSG stacks	25.2	3.2	110.4	13.7
Char Combustor	3.2	1.6	13.9	6.9
HRSG+Combustor	28.4	4.8	124.3	20.6

The applicant estimated CO emissions from the char combustor at 3.2 lb/hr and 13.9 TPY. The basis was the comparison to 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 5 lb/hr and 21.9 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.

The applicant proposes to install oxidation catalyst within the HRSG to control CO and VOC emissions from combustion of BPG. By using oxidation catalyst, there is reasonable assurance that facility-wide emissions of CO and VOC will be substantially less than 250 TPY and insures the facility will not exceed the PSD major stationary source threshold.

5.5. NH_3 Emissions (slip)

The applicant estimated NH_3 (slip) emissions of 4.9 ppmvd @15% O_2 from the SCR system. The Department routinely sets NH_3 limits of 5 ppmvd @15% O_2 for combined cycle projects that rely on wet water injection or DLN combustion in conjunction with SCR for NO_X control to ensure good efficient operation of the control system.

The Department will set an NH_3 limit of 5 ppmvd @15% O_2. This should not be difficult to achieve because the NO_X limit will not be very low (15 ppmvd) in comparison with typical natural gas-fueled combined cycle projects. Also much of the NO_X reduction will be accomplished by the water injection system prior to the SCR system. Estimated annual emissions from the two HRSG stacks will be approximately 23 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 small amount of 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 CTG and DB will minimize emissions of PM/PM_{10}.

The applicant estimated PM/PM_{10} emissions from each HRSG stack at the proposed NWFREC at 2.6 lb/hr and 11.4 TPY. 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 as low as estimated by the applicant. The Department will set a limit 2.6 lb/hr per HRSG stack as estimated by the applicant 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 estimates PM/PM_{10} emissions of approximately 0.6 lb/hr and 2.5 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 limit a PM/PM_{10} limit at 2.5 lb/hr on the char combustor. 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. These measures will suffice to insure low emissions and that the facility will not be a major stationary source of PM/PM_{10} emissions.

The applicant identified materials handling as the other main source of PM/PM_{10} emissions. The associated transfer points will be controlled by baghouses.

5.7. Mercury (Hg) Control

As noted in Table 4 above, estimated emissions of Hg are controlled to approximately 6 lb/yr by the caustic scrubber that is incorporated within the BPG cleanup system. 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 very low compared with the Hg 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.

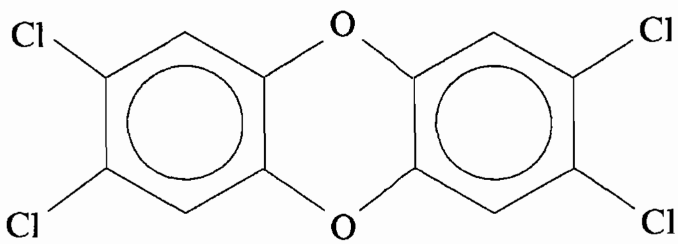

Figure 15 – Skeletal diagram of the 2,3,7,8 TCDD molecule.

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 CTG/DB.

Burning the BPG at high temperatures and with very high excess O_2 in the CTG/DB will destroy any ringed structures including D/F. Finally SCR, such as incorporated into the NWFREC 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:

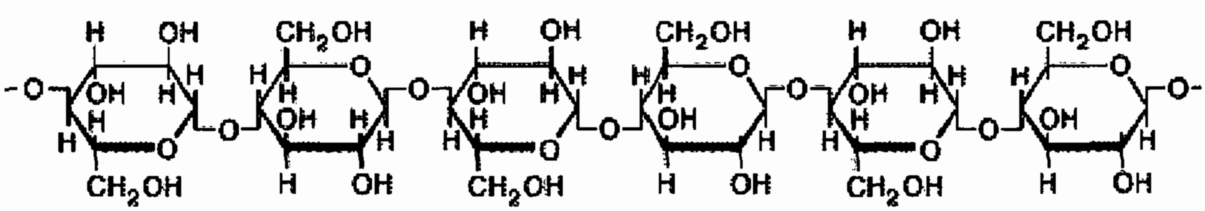

Figure 16 – Skeletal diagram of cellulose.

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.

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 0.15 TEQ ng/dscm. Beyond that value, 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 NWFREC, LLC.

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 25 mmBtu/hr natural gas fired 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 begin 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 approximately 30 TPH. This ramp up of the feed 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 feed, monitor BPG flowrate and the CO and CO_2 composition of the BPG;
- Gradually increase blower airflow into the gasifier using CO and CO_2 levels to determine when woody biomass (carbon) burn 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. However, the applicant provided an ambient air quality analysis to show compliance with the Ambient Air Quality Standards (AAQS). The following sections include the AAQS analysis, a review of current air quality in the vicinity of the project, and information regarding this project and how it relates to other nearby sources of pollution.

7.2. Major Stationary Sources Nearest to the Project

The current largest stationary sources of air pollution in Florida counties within approximately 100 miles of the project site are listed below. The information is from annual operating reports submitted to the Department from 2008 and the future estimate for the NWFREC project.

Table 8. - Largest Sources of SO_2 Nearest to the Project.

Owner	Site Name	TPY
Gulf Power Company	Lansing Smith Power Plant - Bay	15,063
Gulf Power Company	Scholz Power Plant	2,707
Smurfit-Stone Container	Panama City Mill	2,655
St. Marks Powder	St. Marks Powder	72
City of Tallahassee	Hopkins Power Plant	44
NWFREC	**NWFREC (proposed)**	**21**
Arizona Chemical	Port. St. Joe Facility	20

Table 9. - Largest Sources of PM/PM_{10} Nearest to the Project.

Owner	Site Name	TPY
Gulf Power Company	Lansing Smith Power Plant - Bay	803
Smurfit-Stone Container	Panama City Mill	643
Green Energy BioEnergy	Jackson County Facility	158
Coastal Forest Resources Co.	Havana Plywood Plant	148
Gulf Power Company	Scholz Power Plant	128
North Florida Lumber	North Florida Lumber	84
Georgia Pacific Wood Products	Hosford Facility	83
Spanish Trail Lumber Co.	Marianna Sawmill	50
St. Marks Powder	St. Marks Powder	45
City of Tallahassee	Purdom Power Plant	41
Rex Lumber	Graceville Mill	41
NWFREC	**NWFREC (proposed)**	**40**
BASF	Quincy Site	40
City of Tallahassee	Hopkins Power Plant	37

Table 10. - Largest Sources of CO Nearest to the Project.

Owner	Site Name	TPY
Smurfit-Stone Container	Panama City Mill	6,410
Gulf Power Company	Lansing Smith Power Plant - Bay	522
City of Tallahassee	Hopkins Power Plant	365
North Florida Lumber	North Florida Lumber	144
NWFREC	**NWFREC (proposed)**	**134**
Bay County	Bay Waste-to-Energy Facility	120
Georgia Pacific Wood Products	Hosford Facility	106
City of Tallahassee	Purdom Power Plant	106
Spanish Trail Lumber Co.	Marianna Sawmill	100

Table 11. - Largest Sources of VOC Nearest to the Project.

Owner	Site Name	TPY
Smurfit-Stone Container	Panama City Mill	842
St. Marks Powder	St. Marks Powder	445
North Florida Lumber	North Florida Lumber	237
Spanish Trail Lumber Co.	Marianna Sawmill	237
Rex Lumber	Graceville Mill	234
Coastal Forest Resources Co.	Havana Plywood Plant	224
Arizona Chemical	Panama City Facility	211
Trane	Lynn Haven Operation	92
Gulf Power Company	Lansing Smith Power Plant - Bay	78
Northwest Florida Holdings	Allanton Facility	69
Arizona Chemical	Gulf County Facility - Shutdown	56
The Printing House	The Printing House Gadsden	55
Green Energy BioEnergy	Jackson County Facility	49
Chevron	Panama City Terminal	34
Spurlin Industries	Spurlin Industries	33
Georgia Pacific Wood Products	Hosford Facility	30
NWFREC	**NWFREC (proposed)**	**24**
FL Gas Transmission	Station 13 Washington	24

Table 12. - Largest Sources of NO_X Nearest to the Project.

Owner	Site Name	TPY
Gulf Power Company	Lansing Smith Power Plant - Bay	5,733
Smurfit-Stone Container	Panama City Mill	1,518
Gulf Power Company	Scholz Power Plant	1,186
FL Gas Transmission	Station 13 Washington	643
FL Gas Transmission	Station 14 Gadsden	538
City of Tallahassee	Hopkins Power Plant	284
City of Tallahassee	Purdom Power Plant	230
Georgia Pacific Wood Products	Hosford Facility	165
NWFREC	**NWFREC (proposed)**	**165**
Bay County	Bay Waste-to-Energy Facility	134
Green Energy BioEnergy	Jackson County Facility	92
Coastal Forest Resources Co.	Havana Plywood Plant	91

By comparison with other sources in the region, the NWFREC project will be a relatively small source of air pollution.

7.3. Regional Ambient Air Quality Monitoring

The Departments operates more than twenty-three monitors at eleven sites measuring nitrogen oxides (NO_2), SO_2, $PM_{2.5}$ and ozone (O_3). The 2008 monitoring network in the region of the proposed project in Gulf County is shown in the figure below.

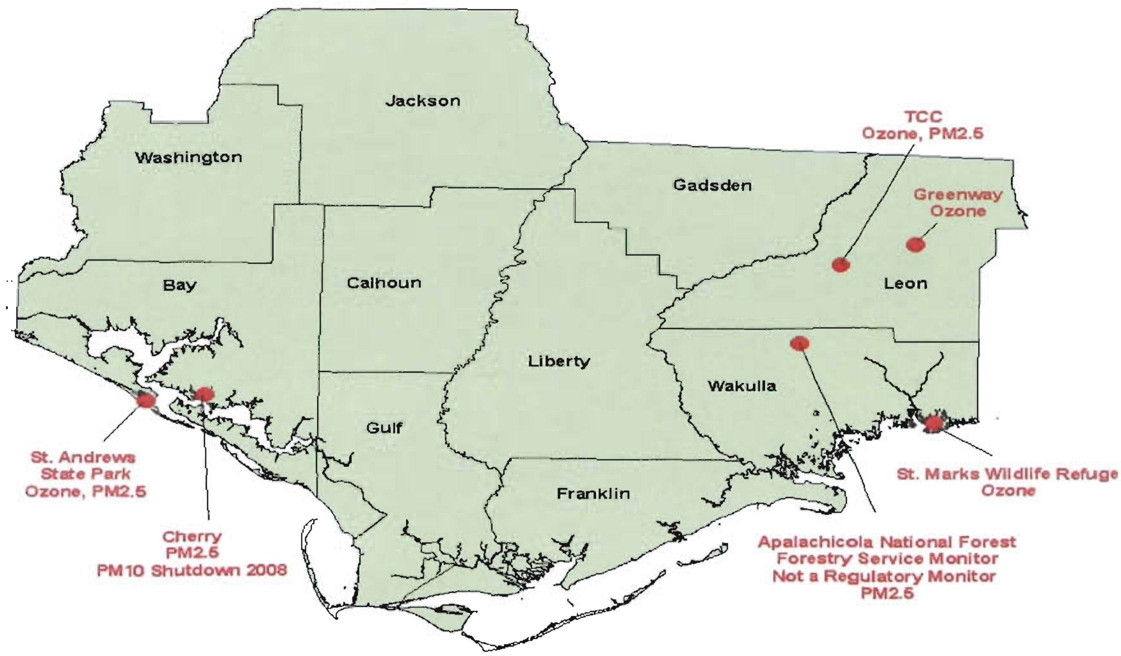

Figure 17. - Ambient Air Monitoring Stations nearest to the Project Location.

Pollutant monitored concentrations are summarized in Table 13. Currently all monitors in Florida are characterized as being in attainment with the AAQS. However some ozone monitors, such as the monitor nearest to the proposed project, are showing concentrations above the standard.

Regardless of further attainment demonstrations with regards to ozone, the proposed project is relatively small in a region that contains much larger sources of ozone precursors (NO_X, VOC). Since ozone is a regional pollutant with levels of concentrations highly dependent on meteorology, it is reasonable to conclude that one minor stationary source with relatively low emissions will not impact ozone concentrations in a significant manner.

While all criteria pollutants are not monitored in the region shown (e.g. CO and SO_2), it is reasonable to assume that the region is in attainment for those pollutants since monitors are placed depending on stationary sources of pollution and population. For example, the nearest sulfur dioxide monitor is located in Hamilton County near the White Springs facility which emitted over 3000 TPY of SO_2 compared with approximately 30 TPY expected from the NWFREC.

Table 13 - Ambient Air Quality Nearest to Project Site (2008).

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units [a]
PM_{10}	Panama City[h]	24-hour	53	50		150 [b]	μg/m³
		Annual			22[i]	50 [c]	μg/m³
$PM_{2.5}$	Panama City	24-hour	28	21		35 [d]	μg/m³
		Annual			10	15 [e]	μg/m³
SO_2	White Springs	3-hour	103	20		500 [f]	ppb
		24-hour	15	8		100 [f]	ppb
		Annual			2	20 [c]	ppb
NO_2	Pensacola	Annual			5	53 [c]	ppb
CO	Jacksonville	1-hour	9	6		35 [f]	ppm
		8-hour	3	3		9 [f]	ppm
Ozone	Panama City	8-hour	85	80		75 [g]	ppb
		4th highest high	75			75 [g]	ppb

a. Units are in: micrograms per cubic meter (μg/m³); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of 24-hour concentrations.
e. Three year average of the weighted annual mean.
f. Not to be exceeded more than once per year.
g. Three year average of the 4th highest daily maximum.
h. No longer operating in 2009.
i. Incomplete data for regulatory purposes.

According to Table 13, the area is in attainment with the $PM_{2.5}$ (also called PM fine) standards. $PM_{2.5}$ 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 (e.g. SO2 and NO_X) are orders of magnitude higher than what would be found locally. Figure 18 shows how a PM fine monitor located in Tallahassee, Leon County was affected by a regional high sulfate (SO_4 from SO_2) event. For reference the peak $PM_{2.5}$ value occurred on September 14, 2005.

The regional nature of the event (and the role of precursors) can be appreciated based on the map in Figure 19 showing a "sulfate" event that occurred on September 14, 2005. The zones of high concentration encompassed a large portion of the Florida Panhandle including Gulf, Leon and other nearby counties.

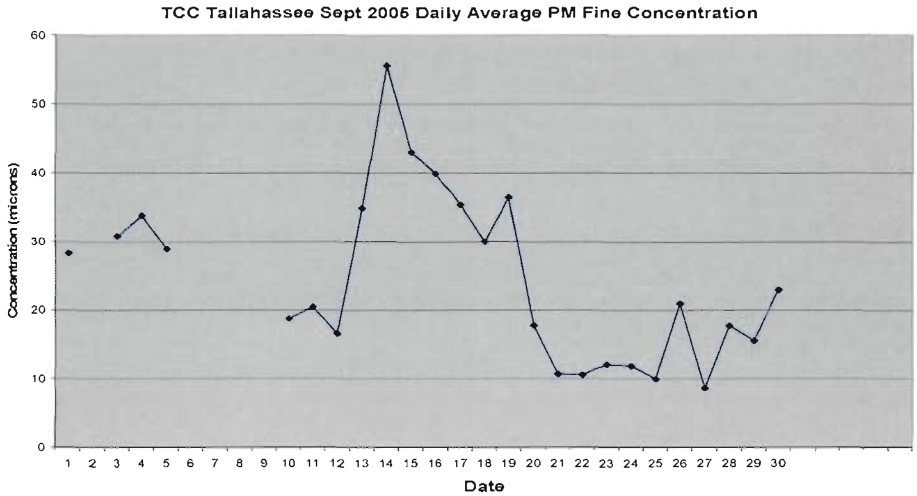

Figure 18. Tallahassee Community College PM fine monitor September 2005.

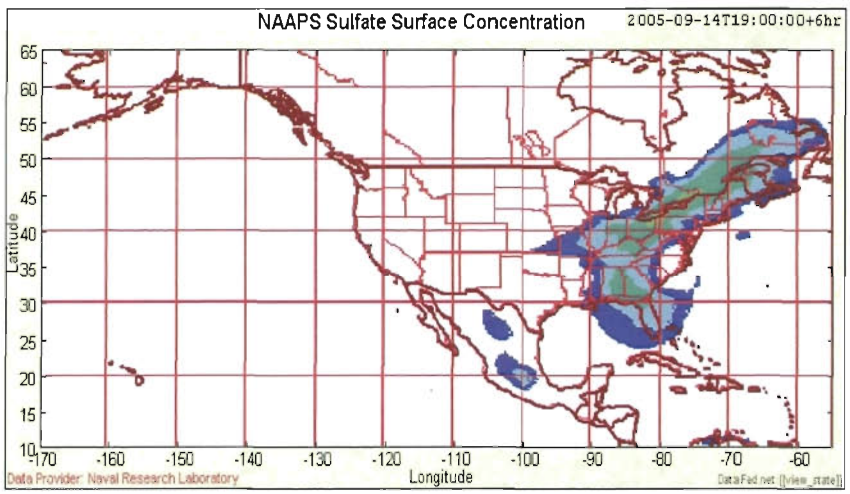

Figure 19. Sulfate Event from September 14, 2005

7.4. Project Ambient Air Quality Impact Analysis

In conducting an ambient air quality impact modeling analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate AAQS to ensure that the proposed project will not cause or contribute to a violation of an AAQS.

A combination of fence line, and non-fence line receptors were chosen for predicting maximum concentrations in the vicinity of the project. The receptor grid consisted of receptors spaced at 50 meter (m) intervals around the facility fence line. The remaining receptors were spaced at 100 m intervals from the property boundary out to 2 km, and 250m spacing from 2 km to 4 km. In addition, receptors were placed 50 km away from the facility to evaluate possible impacts at the Class I St. Marks National Wilderness Area and the Bradwell Bay National Wilderness Area.

Models and Meteorological Data Used in the Ambient Air Quality Analysis

The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Apalachicola Municipal Airport and the Tallahassee Regional Airport respectively. The 5-year period of meteorological data was from 2001 through 2005. The meteorological data used were in accordance with the EPA AERMOD Implementation Guide.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

AAQS Analysis

A modeling analysis was completed to show compliance with the AAQS. The total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The maximum predicted annual and high, second high short term impacts for the AAQS analysis are summarized in Table 14 below. As shown in this table, emissions from the proposed facility are not expected to significantly cause or contribute to a violation of an AAQS.

The results of the Ambient Air Quality Analysis show that the proposed project will not cause or contribute to a violation of an AAQS. The applicant also provided modeling results for PM_{10} including other sources of PM_{10} in the vicinity of the project to further ensure compliance with the AAQS. These results were also below the AAQS.

As stated above, the applicant completed a modeling analysis placing receptors at 50 km away from the proposed project in the direction of the respective Class I area to evaluate possible impacts at the Class I St. Marks National Wilderness Area and the Bradwell Bay National Wilderness Area. The results were compared to the stringent Class I Significant Impact Levels. These levels are the threshold for which additional multi-source modeling would be required.

Table 14. - Ambient Air Quality Impacts.

Pollutant	Averaging Time	NWFREC Impact ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	17	61	78	NO	150
	Annual	4	22	26	NO	50
NO_2	Annual	1	9	10	NO	100
SO_2	3-hour	4	267	271	NO	1,300
	24-hour	3	39	42	NO	260
	Annual	0.2	5	5	NO	60
CO	1-hour	18	10,350	10,368	NO	40,000
	8-hour	26	3,450	3,476	NO	10,000

Table 15 below show the results of this analysis. The conclusion is that the proposed project impacts are less than significant.

Table 15. Class I Area Impacts

Class I Area	Pollutant	Averaging Time	Maximum Concentration	Class I SIL
Bradwell Bay	SO_2	Annual	0.001	0.1
		24-hour	0.031	0.2
		3-hour	0.140	1
	PM_{10}	Annual	0.002	0.2
		24-hour	0.08	0.3
	NO_2	Annual	0.01	0.1
St Marks	SO_2	Annual	0.001	0.1
		24-hour	0.025	0.2
		3-hour	0.142	1
	PM_{10}	Annual	0.002	0.2
		24-hour	0.07	0.3
	NO_2	Annual	0.02	0.1

Conclusion regarding Air Quality

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.

8. 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.

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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, Battelle. The Biomass Gasification Process by Battelle/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 Battelle/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.

DRAFT PERMIT

PERMITTEE

Northwest Florida Renewable Energy Center, LLC
11993 South Street, Route 63
Clinton, Indiana 47842

Authorized Representative:
Mr. Kenn Davis, Manager

Air Permit No. 0450012-001-AC
Expires: December 31, 2013
Northwest Florida Renewable Energy Center
Biomass-Fed Integrated Gasification Combined Cycle
Facility ID No. 0450012
Gulf County

PROJECT AND LOCATION

This permit authorizes the construction of a 47 megawatts (MWnet) biomass-fed integrated gasification and combined cycle power plant called the Northwest Florida Renewable Energy Center (NWFREC). The proposed project location is 521 Premier Drive in Port St. Joe, Gulf County, Florida. The UTM coordinates for this site are Zone 16; 664.16 kilometers (km) East and 3,301.96 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 (Date)
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on ______________________________ to the persons listed below.

Kenn Davis, NWFREC: kdavis@whiteconstruction.com
Glenn Farris, BG&E: glenn@biggreenenergy.com
Dick Fancher, DEP NWD: dick.fancher@dep.state.fl.us
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Jane Sauls, Chair, Leon County Board of County Commissioners: saulsj@leoncountyfl.gov
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John Marks, Mayor, City of Tallahassee: john.marks@talgov.com
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Dave Ciplet: Global Alliance for Incinerator Alternatives: dave@no-burn.org
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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. Bill Sammons: drsammons@aol.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) (Date)

FACILITY AND PROJECT DESCRIPTION

The proposed facility is a 47 MW (net) biomass-fed integrated gasification combined cycle (BIGCC) power plant called the NWFREC. The fuel source for the facility will be exclusively untreated woody biomass that consists primarily of wood chips but may also include agricultural crops and byproducts, logging and lumber mill residues. Municipal solid waste (MSW) is expressly prohibited as a fuel source for the NWFREC.

The woody biomass will be dried and fed into a gasifier vessel containing a heated bed of circulating sand where the woody biomass will be gasified and converted to biomass product gas (BPG). The BPG will be cleaned, compressed and used as fuel in two 16 MW (gross) combustion turbine-electrical generators (CTG). Heat from the CTG exhaust gas will be recovered in two heat recovery steam generators (HRSG) equipped with BPG-fueled duct burners (DB). The resulting steam from the HRSG will drive a single 26.2 MW (gross) steam turbine-electrical generator (STG). The parasitic electrical loads at the facility are estimated to be 11.3 MW resulting in a net electrical power output of 47 MW that can be supplied to the power grid.

This project creates the following new emissions units.

ID No.	Emission Unit Description
001	Biomass handling, storage and drying system
002	Biomass gasifier with natural gas (NG) startup burner
003	Char combustor sand heater with NG startup burner and sand handling equipment
004	BPG flare systems
005	BPG cleanup system
006	16 MW Solar Model No. T-130 BPG-fueled CTG and DB-fired HRSG
007	16 MW Solar Model No. T-130 BPG-fueled CTG and DB-fired HRSG
008	Cooling towers
009	Auxiliary boiler with a maximum heat input rate of 62 mmBtu/hour from firing NG, biodiesel or ultra low sulfur distillate fuel oil (ULSD FO)
010	Miscellaneous support systems

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility operates 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 in accordance with Rule 62-212.400(PSD), F.A.C.
- The facility is subject to the provisions of the Clean Air Interstate Rule (CAIR), including applicable portions of Chapters 62-204, 62-210 and 62-296, F.A.C.
- The facility is subject to Chapter 62-204-800, F.A.C for New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act.

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 Northeast (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 and must be complied with by the permittee:
   a. Appendix A — Identification of General Provisions - NSPS 40 CFR 60, Subpart A;
   b. Appendix BMP — Best Management Practices Plan;
   c. Appendix CC — Common Conditions;
   d. Appendix CEMS — Continuous Emissions Monitoring System (CEMS) Requirements;
   e. Appendix CF — Citation Formats and Glossary of Common Terms;
   f. Appendix CTR — Common Testing Requirements;
   g. Appendix Dc — NSPS, 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;
   h. Appendix GC — General Conditions; and,
   i. Appendix KKKK — 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:

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

(b) 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.

(c) 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 exceeding its projected actual emissions, 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), F.A.C.]

8. <u>Application for Title V Permit</u>: 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. <u>Objectionable Odors Prohibited</u>: 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.]

{Permitting 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.}

10. <u>Open Burning Prohibited</u>: 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.]

11. <u>Unconfined Emissions of Particulate Matter</u>: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Any permit issued to a facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter. Appendix BMP of this permit provides a Best Management Plan (BMP) of reasonable precautions specific to the NWFREC facility to control fugitive PM emissions. Reasonable precautions include the following: a) Paving and maintenance of roads, parking areas and yards; b) Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing; c) Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities; d) Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne; e) Landscaping or planting of vegetation; f) Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter; g) Confining abrasive blasting where possible; and, h) Enclosure or covering of conveyor systems. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the

control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice. [Rule 62-296.320(4)(c), F.A.C.]

12. Excess Emissions: Except as required by specific conditions of this permit dealing with excess emissions with regard to individual emission units, the following conditions apply to excess emissions at NWFREC.
    a. Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
    b. Malfunction: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
    c. Department Discretion: Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.
    d. Department Notification: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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, F.A.C.]

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 Rule 62-210.370(3), F.A.C. Using the computation methods described in Rule 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). [Rule 62-210.370, F.A.C.]

A. Biomass Handling, Storage and Drying System (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 untreated 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 and the best management practices (BMP) are given in Appendix BMP along with a plan for quality control. Deliveries will be made via truck to the site at a rate of approximately 65 trucks per day. The trucks will be unloaded via a truck receiving system equipped with two 75 foot platforms. The biomass fuel will then conveyed, via a series of belt conveyors, to the fuel storage pile. All conveyors are covered, except the main unloading conveyor from the truck dump to the hog tower. This conveyor is uncovered to facilitate the belt magnet and allow for visual inspection of the received fuel for quality control (QC) purposes. The fuel will then be conveyed to an unfired dryer and then to the gasification process area. The fuel storage pile will contain 10 to 14 days of fuel storage.

EQUIPMENT

1. Equipment: The permittee is authorized to construct a biomass handling, storage and drying system consisting of the following equipment.
   a. Truck Unloading System: The truck unloading system dumps into two receiving hoppers and shall be designed to minimize the generation of fugitive dust.
   b. Biomass Belt Conveyor Systems: All belt conveyor systems shall be enclosed and have totally enclosed head boxes, chutes and skirtboard systems to contain the fuel as well as prevent dust generation at the transfer points.
   c. Biomass Storage Pile: The biomass storage pile shall be managed in accordance with Appendix BMP.
   d. Biomass Dryer: The biomass dryer shall use thermal heat transfer (no additional combustion) to dry biomass, if needed, prior to gasification.
   e. Storage/Feeder Bin: The storage/feeder bin shall be enclosed and include a spreader conveyor, a bin vent filter and a bottom screw feeder for unloading.
   f. Bucket Elevator: The bucket elevator shall be enclosed.
   g. Baghouses: Based on the preliminary design, the permittee shall install the following baghouses. Each baghouse shall be designed and maintained to achieve an outlet dust loading rate of 0.01 grains per dry standard cubic feet (gr/dscf) in its exhaust. Based on the final engineering design needs, additional baghouses may be installed as necessary to control fugitive dust from material handling and storage. The Compliance Authority shall be notified 180 days before NWFREC becomes operational of any final engineering design changes. 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.
      1) *Baghouse #1* shall control dust from the transfer points and belts on the conveyor systems at a designed volumetric flow rate of 1,000 standard cubic feet per minute (scfm) exhausted to the atmosphere at ambient temperature.
      2) *Baghouse #2* shall control dust from the transfer points and belts on the conveyor systems and the bucket elevator at a designed volumetric flow rate of 1,000 scfm exhausted to the atmosphere at ambient temperature.
      3) *Baghouse #3* shall control dust from the thermal heat biomass dryer at a design volumetric flow rate of 110,000 scfm exhausted to the atmosphere at approximately 175 degrees Fahrenheit (° F).

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

h. Bin Vent Filter: A bin vent filter shall control dust from the storage/feeder bin. The filter shall be designed and maintained to control at least 99.8% of the inlet dust loading for a designed feed rate of 1,000 tons per day (TPD) on a dry basis.

{Permitting Note: The biomass feed rate in TPD at various points in the process will vary with the corresponding moisture content of the biomass. The approximate processing rates range from 1,000 TPD on a dry basis to 1,820 TPD at a 45 percent moisture content}

{Permitting Note: Enclosed conveyors means that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs.}

[Application No. 0450012-001-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.]

3. Best Management Practice (BMP) Plan: A BMP plan shall be utilized to minimize fugitive PM emissions from receiving, handling, storage and processing of woody biomass. Best management practices shall be utilized to reduce the potential for spontaneous combustion of stored woody biomass and odors. A preliminary BMP plan is contained in Appendix BMP of this permit. This plan also includes quality control and assurance (Q&A) procedures to ensure woody biomass delivered by vendors and suppliers to the NWFREC meet the requirements given in **Condition 6** of this subsection. No later than 180 days before the NWFREC becomes operational, a final BMP plan shall be filed with the Compliance Authority to reflect the final engineering designs of the biomass receiving, handling, storage and processing systems. The final BMP plan will also be incorporate into the Title V operating permit.

PERFORMANCE RESTRICTIONS

4. Approximate Capacities: Each truck dumper will unload approximately 150 tons per hour of biomass with an estimated moisture content of 45%. The covered storage area will hold approximately 12 to 14 days of biomass feedstock (approximately 20,000 tons on a wet basis). The dryer will dry approximately 1,286 TPD of wet biomass per day (assumes moisture content of 30%) and the feeder will transfer approximately 1,000 tons of dry biomass feedstock to the gasifier.
[Application No. 0450012-001-AC; and Rule 62-210.200(PTE), F.A.C.]

5. Restricted Operation: The hours of operation of this emission unit are not limited (8,760 hours per year).
[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

6. Woody Biomass Fuels: Municipal Solid Waste (MSW) is prohibited from use at this facility. The fuel shall consist of untreated woody biomass as described in Appendix-BMP of this permit. Inspection and testing procedures describe in Appendix- BMP shall be followed to insure that appropriate woody biomass is used as fuel and that MSW is not used as fuel. [Rules 62-4.070(3) F.A.C., and 40 CFR 60.51b.]

7. Paved Roadways and Gravel Areas: Fugitive dust emissions from the plant's paved roadways and gravel areas shall be controlled in accordance with **Condition 11 of Section 2** of this permit.
[Rule 62-4.070, F.A.C. Reasonable Assurance, and Rule 62-296.320, F.A.C.]

EMISSIONS STANDARDS

8. Opacity: As determined by EPA Method 9, there shall be no visible emissions (VE) greater than 10% opacity, except for one 6 minute period no greater than 20% from the outlets of the drop points, transfer points, vent screens and baghouses associated with this emission unit.
[Rules 62-4.070(3), 62-297.310(7)(c), and 62-212.400(5)(c), F.A.C.].

TESTING AND MONITORING REQUIREMENTS

9. Initial VE Compliance Tests: The outlets of the drop points, transfer points, silo vent screens associated with the fuel bins and dust collectors of this emissions unit shall be tested to demonstrate initial compliance with the emissions standards for opacity given in **Condition 8** of this subsection. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the emission unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

10. Annual VE Compliance Tests: During each federal fiscal year (October 1st to September 30th), the outlets of the drop points, transfer points, silo vent screens associated with the fuel bins and dust collectors of this emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity given in **Condition 8** of this subsection. [Rule 62-297.310(7)(a)4, F.A.C.]

11. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above method is described in Appendix A of 40 CFR 60 which is included as Appendix A of this permit and is 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]

RECORDS AND REPORTS

13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (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.]

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
002	Biomass gasifier with NG startup burner: The biomass feedstock will be converted in the gasifier by pyrolysis to BPG in a circulating fluidized bed (CFB) of hot sand that uses steam as the fluidization medium. During the process, the sand cools and the biomass feedstock breaks down to produce BPG including tar, char and ash. Cooled sand and char are captured in the gasifier cyclones and returned to the char combustor (EU 003) to support combustion and reheat the sand. The BPG from the gasifier cyclone is cooled in a heat exchanger and then cleaned as described in EU 005 or 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; NG-fueled startup burner; and cyclones.
[Application No. 0450012-001-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 sand from the raw BPG and recirculate it to the char combustor for combustion of the char and reheating of the sand. Another cyclone separator shall be designed, installed and maintained to remove the remaining coarse solid ash prior to BPG cleanup or flaring.
[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Gasifier Capacity: The maximum rate of biomass feed to the gasifier is 1,000 dry tons per day. The gasifier fuel feed rate shall be measured and recorded by permanently installed equipment including but not limited to a belt scale to measure the actual mass flow, and daily gasifier feedstock sampling and analysis to determine the as-fed moisture content.

   The moisture content shall be obtained by using an accepted American Society of Testing and Materials (ASTM) method suitable for wood or woody biomass when used as a fuel. An accepted method suitable for wood or woody biomass as a fuel from the American Society of Mechanical Engineers (ASME) or the American Boiler Manufacturers Association (ABMA) can be used in lieu of an ASTM method. Records of daily feed rate and moisture content shall be available, and retained as accessible records.

   [Application No. 0450012-001-AC and Rules 62-210.200(PTE) and 62-4.070, F.A.C.]

4. Gasifier Startup Burner Capacity: The design heat input rate of the NGs-fueled startup burner is 25 mmBtu per hour. [Application No. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

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. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS APPLICABILITY

6. NSPS Subpart Dc and Subpart A 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 Boilers and Subpart A, General Provisions. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements. The applicable conditions are given in Appendices A and Dc of this permit.
[Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and 40 CFR 60 Subpart A, General Provisions]

C. Char Combustor Sand Heater (EU-003)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
003	Char combustor sand heater with NG startup burner and sand handling equipment: Sand 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 sand. Heated sand is captured in the char combustor cyclones and returned to the gasifier to sustain pyrolysis. Exhaust gas from the char combustor passes through a sand 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/sand heater system consisting of the following equipment: Sand storage silo; CFB char combustor vessel; NG-fueled startup burner; cyclones and a fabric filter baghouse.
[Application No. 0450012-001-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 sand 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 in **Condition 3** of this subsection.
[Application No. 0450012-001-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. Exhaust from these baghouses discharges directly to the ambient air. Should the preliminary design of the baghouses 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. The Compliance Authority shall be notified 180 days before NWFREC becomes operational of any final engineering design changes. 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.
   a. Exhaust from the sand storage silo shall be controlled by a baghouse designed and maintained to limit PM/PM_{10} emissions to 0.03 gr/dscf or better in the baghouse exhaust.
   b. Exhaust from the second char combustor cyclone (ash) separator shall be further controlled by a separate baghouse designed and maintained to 0.01 gr/dscf or better in the baghouse exhaust.

   [Application No. 0450012-001-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 design heat input rate of the char combustor is 124 mmBtu per hour.
[Application No. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

6. Char Combustor Startup Burner Capacity: The design heat input rate of the NG-fueled startup combustor burner is 17 mmBtu per hour. [Application No. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

7. Restricted Operation: The hours of operation of this emissions unit is 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. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS APPLICABILITY

8. NSPS Subpart Dc and Subpart A 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 Boilers and Subpart A, General Provisions. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements. The applicable conditions are given in Appendices A and Dc of this permit.
[Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and 40 CFR 60 Subpart A, General Provisions]

EMISSIONS STANDARDS

9. Char Combustor Baghouse – Opacity Standard: In accordance with EPA Method 9, VE from the second char combustor cyclone (ash) separator baghouse shall not exceed 5% opacity on a 6-minute average as demonstrated by initial and annual compliance tests. [Rules 62-4.070(3) and 62-297.310(7)(c), F.A.C.]

10. Sand Silo Baghouse – Opacity Standard: In accordance with EPA Method 9, VE from the sand silo baghouse 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 exhaust stack shall not exceed 2.5 pounds per hour (lbs/hr) as demonstrated by initial and annual compliance tests.
[Application No. 0450012-001-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 exhaust stack shall not exceed 9.5 lb/hr as demonstrated by initial and annual compliance tests.
[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

13. Sulfur Dioxide (SO_2) Standard: SO_2 emissions from the char combustor exhaust stack shall not exceed 5.0 lb/hr as demonstrated by initial and annual compliance tests.
[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

14. Carbon Monoxide (CO) Standard: Emissions of CO from the char combustor exhaust stack shall not exceed 5.0 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 and results compared with CO process monitor requirements in **Condition 18** of this subsection.
[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

15. Dioxin/furan (D/F): D/F emissions shall meet 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, 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

16. Continuous Opacity Monitoring Systems (COMS): A 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 standard specified in **Condition 9** of this subsection. Opacity shall be based on a 6-minute block average. For the COMS, the 6-minute block averages shall begin at the top of each hour. [Rule 62-4.070(3), F.A.C.]

17. 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)]

18. CO Process Monitor: At least one process monitor shall be installed no later than 180 days after initial operation 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.]

19. Opacity Compliance Tests: The sand silo and char combustor baghouses shall be tested for 30 minutes to demonstrate initial compliance with the opacity standard specified in **Conditions 9 and 10** of this subsection 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 sand silo baghouse 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.]

20. CO, PM/PM_{10}, NO_X, SO_2 and D/F Compliance Tests: The char combustor exhaust stack shall be tested to demonstrate initial compliance with the CO, PM/PM_{10}, NO_X, SO_2 and D/F 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, SO_2 and D/F standards. [Rule 62-4.070(3), F.A.C.]

21. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

22. 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, 5B, 17	Determination of Particulate Emissions.
6C	Measurement of SO_2 Emissions (Instrumental)
EPA 7E	Determination of NO_X Emissions (Instrumental).
EPA 9	Visual Determination of Opacity.
EPA 10	Measurement of Carbon Monoxide Emissions (Instrumental).
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{For concurrent use with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates
EPA 23	Measurement of Dioxin/Furan Emissions.
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

RECORDS AND REPORTS

Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (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.]

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
004	BPG flare systems: The flare systems shall only be used to flare BPG gas during startup, planned shutdown, and emergency shutdown (e.g. CTG/DB or gasifier trips). Raw BPG from the biomass gasifier (EU-002) may be flared and not sent to the BPG cleanup system (EU-005). Cleaned, sweetened BPG from the cleanup system may be flared and not further processed for use in the CTG/DB (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. 0450012-001-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 BPG with a design heat input rate of 150 mmBtu per hour. NG shall be used as fuel for the pilots.
[Application No. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

3. Restricted Operation: Although the hours of operation of the flare systems are not limited, the applicant anticipates that the flares will operate approximately 100 hours per year (hr/yr). The flare systems shall only be used to flare BPG gas during startup, planned shutdown, and emergency shutdown (e.g. CTG/DB or gasifier trips). [Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

4. Visible Emissions (VE) Standard: The flares shall be designed for and operated with no VE except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [Rules 62-4.070(3), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

5. VE Compliance Tests: The flare system exhaust shall be tested to demonstrate initial compliance with the VE standard given in **Condition 4** of this subsection no later than 180 days after initial operation and during each federal fiscal year (October 1st to September 30th) thereafter. EPA Method 22 VE compliance test shall be used to determine the compliance of the flare with the VE requirements. The observation period is 2 hours and shall be used according to Method 22. [Rule 62-4.070(3), F.A.C.]

6. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
EPA 22	Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares 2 Hour Duration

8. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare systems 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 the 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 flare

pilot flames shall be monitored using a thermocouple or any other equivalent device to detect the presence of flames. [Rules 62-4.070(3) F.A.C.]

RECORDS AND REPORTS

9. 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.]

10. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]

E. BPG Cleanup System (EU-005)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
005	BPG Cleanup System: The BPG cleanup system consists of specialized oil scrubbers and an aqueous scrubber with a caustic section. 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 ammonia (NH_3), hydrogen sulfide (H_2S) and hydrogen chloride (HCl) is 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 CT/DB (EU-006 and 007) or flared (EU-004).

EQUIPMENT

1. Equipment: The permittee is required to construct a BPG cleanup system consisting of the following control equipment. None of the control equipment shall discharge directly to the ambient air.
   a. Oil Based Scrubber: 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. Aqueous Scrubber: An aqueous scrubber that is designed to remove inorganic impurities.

   [Application No. 0450012-001-AC and Rules 62-4.070(3), F.A.C.]
2. Circumvention: The permittee shall not circumvent the BPG cleanup system except during startup, planned shutdown, and emergency shutdown (e.g. CTG/DB or gasifier trips). [Application No. 0450012-001-AC and Rules 62-4.070(3) and 62-210.650, F.A.C.]

TAR HANDLING AND STORAGE

3. Tars shall be continuously returned to the char combustor and not accumulated, stored or disposed of on-site or off-site. [Application No. 0450012-001-AC and Rules 62-4.070(3), F.A.C.]

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
006	One 16 MW (gross) BPG-fueled Solar T-130 CTG and supplementary-fired HRSG with a nominal 71 mmBtu/hour BPG-fueled DB. Steam from the HRSG is used in the shared 26.2 MW (gross) STG.
007	One 16 MW (gross) BPG-fueled Solar T-130 CTG and supplementary-fired HRSG with a nominal 71 mmBtu/hour BPG-fueled DB. Steam from the HRSG is used in the shared 26.2 MW (gross) STG.

EQUIPMENT

1. CTG: The permittee is authorized to install, tune, operate and maintain a combined cycle CTG system consisting of the following equipment: two 16 MW BPG-fueled Solar T-130 CTG; two inlet air filtration systems; two automated CTG control systems; two HRSG with BPG-fueled DB systems; two HRSG stacks; and a shared 26.2 MW STG. NG, biodiesel or ULSD FO will be used during commissioning and during startups, malfunctions and shutdowns. [Application No. 0450012-001-AC and Rule 62-4.070(3), F.A.C.]
2. Wet Injection: The permittee shall install, operate, and maintain a wet injection system (water or steam) to reduce NO_X emissions from each CTG. Prior to the initial emissions performance tests required for each CTG, the wet injection system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional oxidation catalyst and SCR control technology described below. Thereafter, each CTG shall be maintained and tuned in accordance with the manufacturer's recommendations.
3. Selective Catalytic Reduction (SCR) Systems: The permittee shall install an SCR system for each CT/HRSG exhaust stream to control NO_X emissions and further assist in D/F 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 indicated in this subsection. The SCR system shall be designed to achieve a maximum ammonia slip level of 5 ppmvd @ 15% oxygen.
[Application No. 0450012-001-AC and Rule 62-4.070(3), F.A.C.]
{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.}
4. Oxidation Catalyst Systems: The permittee shall install an oxidation catalyst system for each CT/HRSG exhaust stream to control CO and VOC emissions. Each oxidation catalyst system shall be designed, constructed and operated to achieve the permitted levels of CO emissions specified in the subsection. [Application No. 0450012-001-AC and Rule 62-4.070(3), F.A.C.]
5. 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 subsection.
[Rules 62-210.650 and Rule 62-4.070(3), F.A.C.]
6. 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 from each combustion turbine exhaust stream within 60 calendar days after achieving permitted capacity.
[Application No. 0450012-001-AC; Rule 62-4.070(3), F.A.C.; and Subpart KKKK in 40 CFR 60]
7. CO CEMS: The permittee shall install, calibrate, operate and maintain a CEMS to continuously monitor and record CO emissions from each combustion turbine exhaust stream within 60 calendar days after achieving permitted capacity. [Application No. 0450012-001-AC; Rule 62-4.070(3), F.A.C]

PERFORMANCE RESTRICTIONS

8. Authorized Fuels: The only authorized fuels for the CTG and DB systems are:

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

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

   c. Biodiesel (if available) or ULSD FO containing 0.0015% sulfur or less.

   {Permitting Note: only BPG can be burned in the DB; NG, biodiesel or ULSD FO cannot be used}

   [Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

9. Permitted Capacities:

   a. CTG: The maximum heat input rate of each CTG is 161 mmBtu/hour on a 4 hour average basis. 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 NG. Heat input rates will vary depending upon CTG characteristics, ambient conditions and alternate methods of operation. 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 design heat input rate of each DB located within each HRSG is 71 mmBtu per hour based on the LHV of BPG. [Application No. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

   {Permitting Note: The estimated LHV is 435 British thermal unit per standard cubic foot (Btu/scf) for BPG and 980 Btu/scf for natural gas.}

10. Restricted Operation: Each CTG shall fire NG, biodiesel or ULSD FO no more than a combined 750 hours at permitted capacity during any consecutive 12 month period. When firing the CTG at less than the permitted capacity, fuel usage shall be prorated over the hours of operation by reducing the hours when firing the fuel based on the percentage of the fired capacity compared to the maximum, e.g. 90 percent (5 hours x 0.9 = 4.5 hours of fuel firing). The hours of operation are not otherwise limited (8,760 hours per year). [Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

11. Authorized Method of Operation: Both CTG are permitted to operate only as part of a combined cycle system. [Application No. 0450012-001-AC]

NSPS APPLICABILITY

12. NSPS Subpart KKKK and Subpart A Applicability: The CTG 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 CTG and DB constructed after February 18, 2005 and Subpart A, General Provisions.

    [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 KKKK of this permit) and 40 CFR 60 Subpart A, General Provisions (see Appendix A of this permit].

EMISSION LIMITS

13. Emission Standards: The following standards are at least as stringent as the Subpart KKKK limits described in **Condition 12** of this subsection and in Appendix KKKK 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 each CTG/DB systems shall not exceed the following standards.

F. BPG-Fueled CTG and DB-Fired HRSG (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
CO [b]	CTG (BPG)	25.0	9.5	23.0, 30 unit operating day rolling average	N/A
	CTG & DB (BPG)	23.0	12.6		
	CTG (NG)	NA	12.1		N/A
	CTG, All Modes and All Fuels	N/A	12.6	N/A	12.6, 12-month rolling, rolled monthly
NO_X [c]	CTG (BPG)	15.0	9.3	15.0, 30 unit operating day rolling [g h]	N/A
	CTG & DB (BPG)	15.0	13.7		
	CTG (NG)	25.0	8.8		
	CTG All Modes and All Fuels			N/A	13.7 lb/hr 12-months rolling, rolled monthly
PM/PM_{10} [d]	All Modes and All Fuels	N/A	2.6	N/A	
		Fuel Specification: 20 gr S/100 SCF in NG, 0.02% S in BPG and 0.0015% in biodiesel or ULSD FO			
		Visible emissions shall not exceed 10% opacity for each 6-minute block average.			
SAM/SO_2 [e]	All Modes and All Fuels	20 gr S/100 SCF in NG, 0.02% S in BPG and 0.0015% S in biodiesel or ULSD FO [h]			
Ammonia [f]	CTG All Modes and All Fuels	5	NA	NA	

a. Parts per million by volume dry (ppmvd) corrected to 15% oxygen (O_2).

b. Continuous compliance with the 30 day rolling average CO standard shall be demonstrated based on data collected by the required 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 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 CTG 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 for NG and BPG shall be determined by the ASTM method D5504-8 while ASTM method D5453-09 shall be used for biodiesel or ULSD FO. In lieu of ASTM testing, the permitted can accept fuel supplier/vendor reports on fuel sulfur content.

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. 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 be in accordance with the 40 CFR 60, NSPS, Subpart KKKK for NO_X as described in 60.4380(b)(1).

[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

14. Ammonia Slip: Each SCR system shall be designed to achieve a maximum ammonia slip of 5 ppmvd @ 15% oxygen. Actual ammonia slip levels shall not exceed 5 ppmvd @ 15% oxygen as determined by EPA Method CTM-027 based on the average of three test runs. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

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 CTG 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.

16. 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.

17. 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.]

GENERAL COMPLIANCE REQUIREMENTS

MONITORING

18. 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 NG, biodiesel and ULSD FO, the permittee shall either obtain reliable fuel sulfur data from the fuel vendor or analyze a weekly sample for the fuel sulfur content.

[Application No. 0450012-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

RECORDS AND REPORTS

19. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CTG 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]

20. 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 each CTG from each fuel (mmBtu); the total heat input rate to the duct burner (mmBtu); and the 12-month rolling total of NO_X and CO emissions (tons). Annual NO_X and CO emissions shall be determined in accordance with Rule 62-210.370, F.A.C. 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.]

21. 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 in 40 CFR 75.
[Rule 62-297.310(8), F.A.C.]

PERFORMANCE TESTS

22. Initial Compliance Tests: Each CTG shall be tested to demonstrate initial compliance with the emissions standards for CO, NO_X, 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. Each CTG 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.]

23. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emissions standards for opacity and ammonia slip. Each CTG 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.]

24. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

25. 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.
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

26. 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 CTG 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. See Appendix CEMS of this permit for additional CEMS requirements.

    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.

27. 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 with zeros. 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.]

28. 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 each 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 CTG 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 CT/HRSG/STG systems and the cooling of compressor gases with mist eliminators designed for a drift rate of 0.002% of the circulating water flow rate.
   [Application No. 0450012-001-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. 0450012-001-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 cooling tower systems. [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: The auxiliary boiler fires NG, biodiesel or ULSD FO with a maximum heat input rate of 62 mmBtu/hour to start up the biomass gasification system. Exhaust gases exit a stack with design parameters of 2.75 feet in diameter, 50 feet in height, and a flow rate of 29,000 acfm and an exit temperature of 296 degrees ° F.

EQUIPMENT

1. Auxiliary Boiler: The permittee is authorized to install an auxiliary boiler rated at 62 mmBtu/hour of heat input from firing NG, biodiesel or ULSD FO. The auxiliary boiler shall only be operated for purposes of starting up the gasification system. [Application No. 0450012-001-AC]

PERFORMANCE RESTRICTIONS

2. Authorized Fuel: The auxiliary boiler shall fire only NG with a maximum fuel sulfur content of 20 grains/100 scf or biodiesel or ULSD FO with a sulfur content of 0.0015 percent or less. [Application No. 0450012-001-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 4-hour average. [Application No. 0450012-001-AC and Rule 62-210.200(PTE), F.A.C.]

4. Restricted Operation: The auxiliary boiler shall fire a combination of NG, biodiesel or ULSD FO no more than 500 hours at permitted capacity in any consecutive 12 month period. If the boiler is fired at less than the permitted capacity the operational hours shall be prorated. The hours of operation of are not otherwise limited. [Application No. 0450012-001-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 NG, biodiesel or ULSD FO as the only authorized fuels. [Rule 62-296.406, F.A.C.]

6. NSPS Subpart Dc and Subpart A 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 Boilers and Subpart A, General Provisions. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements. The applicable conditions are given in Appendices A and Dc of this permit.
[Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and 40 CFR 60 Subpart A, General Provisions]

EMISSIONS STANDARDS

7. Opacity Standard: In accordance with EPA Method 9, VE shall not exceed 20% opacity except for one 6-minute period per hour that shall not exceed 27% opacity.
[Application No. 0450012-001-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 given in **Condition 7** of this subsection 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 given in **Condition 7** of this subsection. [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 CTR (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 CTR (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 non regulated emissions units.

ID No.	Emission Unit Description
010	Miscellaneous support systems

EQUIPMENT

1. Equipment: The permittee is authorized to construct the following support equipment for this project.
   a. A water treatment system for the boilers;
   b. A wastewater treatment system for process wastewater;
   c. An ash handling system;
   d. Gas compressor systems for the BPG and NG; and,
   e. Miscellaneous diesel (biodiesel) and/or ULSD FO storage tanks.

   [Application No. 0450012-001-AC]

SECTION 4. APPENDICES

CONTENTS

SUBPART A – GENERAL PROVISIONS

The owner or operator shall comply with all applicable provisions of 40 CFR 60 Subpart A, which is available at the following link:

40 CFR 60, Subpart A

PRELIMINARY BEST MANAGEMENT PRACTICES (BMP) PLAN FOR MINIMIZATION OF FUGITIVE DUST, PILE MANAGEMENT AND FIRE PREVENTION

The permittee shall comply with this BMP plan and any update hereto.
[Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: The preliminary BMP plan will be updated by NWFREC as the engineering of the Biomass Receiving, Handling, Storage and Processing emission unit (EU-001) is finalized. The final BMP plan must be submitted to the Compliance Authority no later than 180 days before the NWFREC facility becomes operational.}

Measures to Minimize Fugitive Emissions	
1)	Conveyor systems and associated drop points shall be enclosed to the extent practicable to minimize exposure to air currents. Enclosed conveyors means that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs
2)	Drop points to woody biomass storage areas shall be designed to minimize the overall drop height exposed to air current.
3)	Periodic equipment inspection and maintenance shall be performed to maintain the integrity of conveyor systems and associated drop point enclosures. Appropriate plant records shall be maintained on equipment maintenance performed.
4)	Fuel silos shall be equipped with vent filters.
5)	Plant personnel shall conduct daily inspections of the conveyor systems and associated drop point integrity to identify any equipment abnormalities.
6)	Signs shall be posted identifying warning signs of potential equipment malfunction.
7)	Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.
8)	Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall monitor truck unloading operations and if excessive fugitive dust is detected plant personnel shall implement appropriate fugitive dust minimization techniques. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations.
9)	All major roadways at the plant shall be paved.
10)	Mud, dirt, spilled biomass or similar debris shall be removed promptly from the paved roads.
11)	Plant personnel shall be trained on what constitutes excessive dust on paved roads.
12)	Transfer points and fuel bins are equipped with vent filters.
13)	Fuel handling equipment shall be inspected for proper operation and for maintenance requirements.
14)	Plant fuel handling personnel shall implement procedures for monitoring and controlling unplanned fugitive dust emissions, including truck handling and unloading, and dirt or spilled biomass fuel on roads.
15)	Plant personnel shall will spray, wash, scrape, or otherwise remove dirt or spilled biomass fuel on plant roads as necessary to reduce fugitive emissions.

Measures for Storage Pile Management	
1)	A woody biomass storage pile fugitive dust management plan shall be developed and maintained onsite. The plan shall identify warning signs and identify corrective actions for conditions that could result in excessive wind erosion and fugitive dust formation. Plant personnel shall be trained to recognize such warning signs.
2)	Operational plans will recognize conditions such as high winds likely to result in wind erosion and excessive fugitive dust and will instruct plant personnel to curtail movement of fuel by mobile equipment under such conditions.
3)	Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days.
4)	First in first out biomass utilization shall be implemented to minimize objectionable odors.
5)	The woody biomass storage areas shall be monitored and if conditions are conducive to wind erosion and fugitive dust formation, procedures from the fugitive dust plan shall be implemented.
6)	Mobile equipment will be used to maintain the pile's design shape and to ensure adherence to FIFO in reclaim operations.
Measures to Minimize Spontaneous Combustion	
1)	A fire management plan (FMP) shall be developed to identify and list the causes and conditions giving rise to spontaneous combustion.
2)	Contact local fire marshal to develop fire management plan. The FMP shall be maintained on site.
3)	The FMP shall include: a) requirement to train onsite personnel to handle incipient fires and training on the identification of potential fire hazards; and, b) install and maintain equipment for plant personnel to handle incipient fires. The local fire department shall be invited to participate in onsite training.
4)	Sufficient inspections of the woody biomass storage areas shall be performed by plant personnel to identify potential fire hazards. Plant personnel shall be trained on identification of potential fire hazards.
5)	Signs which identify potential fire hazards shall be posted at the plant.
6)	Incoming unprocessed materials shall be stored in areas in accordance with clearance ranges between each storage area as described in the FMP.
7)	The stacker reclaimer shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material.
8)	Compaction of woody biomass materials in the storage areas shall be minimized.
9)	Fuel pile fire protection equipment may be used for minimization of fugitive dust emissions and dust suppression as required.
10)	Plant personnel shall conduct daily inspection for fire hazards and monitor the hazards using video surveillance.
11)	The FMP shall describe the use of fire-water cannons, mounted on elevated structures, together with mobile equipment to uncover and rapidly extinguish any smoldering materials.
12)	The size of the fuel storage pile will not exceed the design value – this is a primary control measure, based upon the limited on-site fuel storage of about 2 weeks' worth of fuel. Specifically, the stacker will build a pile in zones up to a maximum of 60 feet high (an average of 40 feet high) and the reclaimer will start with the first zone built and reclaim the pile down to within two inches of grade.
Measures for the Control of Permitted Feedstock	
Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to <u>clean woody</u> biomass meaning trees and woody plants, including limbs, tops, trunks, needles, leaves, stalks and other woody parts, grown in a forest, woodland, rangeland environment, tree farm or agricultural crop farm. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass.	

According to NWFREC, 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. The woody biomass feedstock will be delivered via truck to the site at a rate of approximately 65 trucks per day.

NWFREC has identified the following available woody biomass feedstock types for their facility: saw dust; hogged fuel; processed butt cuts, and fuel crop.

Saw Dust is defined as a by-product of forest and forest product operations.

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.

Butt Cuts are untreated round residues that are either of oversized or undersized non processible materials from post or pole manufacturers.

Fuel Crop is a vegetative product specifically grown for energy use or a waste product of agricultural operations (e.g., corn stover, peanut hulls, etc.).

The following is required from the permittee:

1) Woody biomass feedstocks shall be obtained from vendors that certify that the woody biomass feed stocks they supply to NWFREC meet the definition of woody biomass specified above. In addition, the vendor must certify that the woody biomass does not contain any of the prohibited items listed in **Item 10,** 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) The woody biomass feedstock will be delivered to the NWFREC Plant in vehicles designed to prevent release. Woody biomass feedstock shall be delivered to NWFREC primarily by trucks.
4) The permittee shall inspect each shipment of woody biomass upon receipt for any material not specifically identified in this plan. If the permittee identifies any such material, the material shall be rejected and/or marshaled in specified areas until proper disposal can be arranged. Rejected materials shall be moved off site in a logistically reasonable time period.
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 and the material description 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 **Item 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 permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.
10) The following items <u>are not</u> considered woody biomass and are expressly prohibited:

a) those materials that are prohibited by state or federal law; b) plastics; c) woody biomass that has been chemically treated or processed; d) yard trash; e) municipal solid waste; f) paper; g) treated wood such as CCA or creosote; h) painted wood; and i) wood wastes from landfills.
Measures to Minimize Ash Fugitive Dust
The ash will be collected in a series of primary and secondary cyclones as the flue gas exits the gasifier combustor. It will drop through the cyclones into an ash hopper and will be quenched with water to both lower the temperature for handling and control (PM) dust emissions. When the hopper is full, the ash will exit the hopper from the bottom into a truck and then covered to leave the site for disposal. Tars that are recovered shall be contained within a closed loop system and recycled to the char combustor.

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the NWFREC 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: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such 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*

(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 April 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.]

CEMS OPERATION PLAN

1. CEMS Operation Plan: The owner or operator shall create and implement a facility-wide plan for the proper installation, calibration, maintenance and operation of each CEMS required by this permit. The owner or operator shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the owner or operator shall submit a new or revised plan for approval.

{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at (850)488-0114.}

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Timelines:
   a. *New and Existing Emission Units.* For new emission units, the owner or operator shall install each CEMS required by this permit prior to initial startup of the unit. The owner or operator shall conduct the appropriate performance specification for each CEMS within 90 operating 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.
3. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR part 60, Appendix B.
4. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.
5. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR part 60, Appendix B, Performance Specification 6.
6. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach.
7. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

{Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}

8. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit.
   a. *CO Monitors:* For CO monitors, the owner or operator shall conduct Performance Specification 4 or 4A of 40 CFR part 60, Appendix B
   b. *NO_X Monitor:* For a NO_X monitor, the owner or operator shall conduct Performance Specification 2 of 40 CFR part 60, Appendix B.

c. *COMS*: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

9. Quality Assurance: The owner or operator shall follow the quality assurance procedures of 40 CFR part 60, Appendix F.

   a. *CO Monitors:* The required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR part 60 and shall be based on a continuous sampling train.

   b. *NO_X Monitors:* The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR part 60. NO_X shall be expressed "as NO_2."

10. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

CALCULATION APPROACH

11. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.

12. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per Condition 19 of this appendix.

13. Operating Hours and Operating Days: For purposes of this appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

14. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

b. *Rolling12-month average, rolled monthly:* Compliance shall be determined after each operating month by calculating the arithmetic average of all the valid hourly averages from that operating month and the prior x-1 operating months.

MONITOR AVAILABILITY

16. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required 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.

EXCESS EMISSIONS

17. Definitions:

    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* means the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* means 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.

18. 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.

19. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The data exclusion procedures of this condition apply only to SIP-based emission limits.

    a. *Excess Emissions.* Data in excess of the applicable emission standard may be excluded from compliance calculations if the data are collected during periods of permitted excess emissions (for example, during startup, shutdown or malfunction). The maximum duration of excluded data is 2 hours in any 24-hour period, unless some other duration is specified by this permit. For the CEMS on the HRSG stacks at the NWFREC facility, excess emissions of NO_X and CO during periods of startup, shutdown and malfunction cannot be excluded. This is to ensure that the 250 TPY emission limits for these pollutants are not exceeded which if they were would trigger PSD regulations.

    b. *Limited Data Exclusion.* If the compliance calculation using all valid CEMS emission data, as defined in Condition 12 of this appendix, indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The underlying event (for example, the startup, shutdown or malfunction event) must precede the data exclusion. If there is no underlying event, then no data may be excluded. Only data collected during the event may be excluded.

d. *Reporting Excluded Data.* The data exclusion procedures of this condition are not necessarily the same procedures used for excess emissions as defined by federal rules. Quarterly or semi-annual reports required by this permit shall indicate not only the duration of data excluded from SIP compliance calculations but also the number of excess emissions as defined by federal rules.

20. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. For malfunctions, notification is sufficient for the owner or operator to exclude CEMS data.

ANNUAL EMISSIONS

21. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 12 of this appendix, shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit or RAA. These periods of time shall be considered missing data for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.

22. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

23. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

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

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

F: 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

Application

NWFRC: Northwest Florida Renewable Energy Center

BIGCC: biomass-fed integrated gasification combined cycle

BPG: biomass product gas

HRSG: heat recovery steam generators

CT: combustion turbine-electrical generators

DB: duct burners

CEMS: continuous emissions monitoring system

COMS: continuous opacity monitoring system

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.]

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. These units are subject only to record keeping and reporting requirements since these combustion units fire only natural gas.

The entire regulation is accessible at the following link:

Link to Subpart Dc

{Note: Only applicable definitions have been included below.}

§ 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 (SO_2) 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.

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, Florida Statutes. 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), Florida Statutes, 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 Florida Statutes 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 Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. 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 Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code 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 ( );
    b. Determination of Prevention of Significant Deterioration ( ); and
    c. Compliance with New Source Performance Standards (X).
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.

NSPS – STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES

The NWFREC combustion turbines 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 the below web link:

Link to Subpart KKKK

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

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

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[2] at 15% oxygen

1. Only the portion of the table that includes the NO_X requirements applicable to the NWFREC project.
2. Permittee proposes a NO_X emission standard of 14.9 ppmvd (15 ppmvd is emission limit in permit) for the NWFREC project when firing BPG in CTG and DB in lieu of the specified 74 ppmvd emission standard.

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Thursday, January 28, 2010 4:13 PM
To: 'kdavis@whiteconstruction.com'
Cc: 'glenn@biggreenenergy.com'; 'dick.fancher@dep.state.fl.us'; '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'; 'susiecaplowe@comcast.net'; 'dave@no-burn.org'; 'bradley@greenaction.org'; 'nseldman@ilsr.org'; 'dmellman@post.harvard.edu'; 'ring@tampabay.rr.com'; 'drsammons@aol.com'; Linero, Alvaro; Read, David; Heron, Teresa; Walker, Elizabeth (AIR)
Subject: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC
Attachments: 0450012-001-AC NWFRECIntent.pdf

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** 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".

Note: 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/0450012.001.AC.D_pdf.zip

Owner/Company Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Project Number: 0450012-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: Teresa Heron

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/emission/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

Livingston, Sylvia

From: Kenn Davis [kdavis@WhiteConstruction.com]
Sent: Thursday, January 28, 2010 8:21 PM
To: Livingston, Sylvia
Subject: RE: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC

Thank you, we can access the files. ,

Kenn Davis

Northwest Florida Renewable Energy Center
General Manager
Tel: 765-832-8526
Fax: 765-832-1860
kdavis@whiteconstruction.com

NORTHWEST FLORIDA
RENEWABLE ENERGY CENTER

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Thursday, January 28, 2010 4:13 PM
To: Kenn Davis
Cc: glenn@biggreenenergy.com; 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; susiecaplowe@comcast.net; dave@no-burn.org; bradley@greenaction.org; nseldman@ilsr.org; dmellman@post.harvard.edu; ring@tampabay.rr.com; drsammons@aol.com; Linero, Alvaro; Read, David; Heron, Teresa; Walker, Elizabeth (AIR)
Subject: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC

Dear Sir/ Madam:

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Owner/Company Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
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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

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Note: The attached document is 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

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.

Livingston, Sylvia

From: Bob Fulford [bobfulford@nettally.com]
Sent: Friday, January 29, 2010 9:33 AM
To: Livingston, Sylvia
Subject: Re: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC

----- Original Message -----
From: Livingston, Sylvia
To: kdavis@whiteconstruction.com
Cc: glenn@biggreenenergy.com ; 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 ; susiecaplowe@comcast.net ; dave@no-burn.org ; bradley@greenaction.org ; nseldman@ilsr.org ; dmellman@post.harvard.edu ; ring@tampabay.rr.com ; drsammons@aol.com ; Linero, Alvaro ; Read, David ; Heron, Teresa ; Walker, Elizabeth (AIR)
Sent: Thursday, January 28, 2010 4:13 PM
Subject: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** 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".

Note: 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/0450012.001.AC.D_pdf.zip

Owner/Company Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Project Number: 0450012-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: Teresa Heron

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/emission/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

Livingston, Sylvia

From: joecain1@comcast.net
Sent: Thursday, January 28, 2010 6:22 PM
To: Livingston, Sylvia
Subject: Re: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC

Thanks... Information was readily visible.

Looks very similar to that submitted for the Tallahassee site, which I believe was very acceptable. Less pollution than from a residential wood burning fireplace!

----- Original Message -----
From: "Sylvia Livingston" <Sylvia.Livingston@dep.state.fl.us>
To: kdavis@whiteconstruction.com
Cc: glenn@biggreenenergy.com, "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, susiecaplowe@comcast.net, dave@no-burn.org, bradley@greenaction.org, nseldman@ilsr.org, dmellman@post.harvard.edu, ring@tampabay.rr.com, drsammons@aol.com, "Alvaro Linero" <Alvaro.Linero@dep.state.fl.us>, "David Read" <David.Read@dep.state.fl.us>, "Teresa Heron" <Teresa.Heron@dep.state.fl.us>, "Elizabeth Walker (AIR)" <Elizabeth.Walker@dep.state.fl.us>
Sent: Thursday, January 28, 2010 4:13:23 PM GMT -05:00 US/Canada Eastern
Subject: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.; 0450012-001-AC

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** 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".

Note: 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).

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http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0450012.001.AC.D_pdf.zip

Owner/Company Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Facility Name: NORTHWEST FLA RENEWABLE ENERGY CTR, LLC.
Project Number: 0450012-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: GULF
Processor: Teresa Heron

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:

0450012-00-AC
ANDRES RODRIGUEZ
1204 MICCOSUKEE ROAD
TALLAHASSEE, FL 32308

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X R. Carlin
☐ Agent
☐ Addressee

B. Received by (Printed Name)
R. Carlin

C. Date of Delivery
02/02/10

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 1820 0007 9819 9037

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

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TALLAHASSEE, FL 32399-2400

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Sent 1/29/10
0450012-001-AC
Rtn 2/3/10

7005 1820 0007 9819 9037

Sent To Andres Rodriguez
Street, Apt. No.; or PO Box No. 1204 Miccosukee Rd
City, State, ZIP+4 Tall Fl 32308

PS Form 3800, June 2002 See Reverse for Instructions