Florida Department of Environmental Protection

Memorandum

TO: Trina Vielhauer, Bureau of Air Regulation

FROM: Al Linero and Teresa Heron, Special Projects Section

DATE: April 13, 2009

SUBJECT: DEP File No. 0990042-006-AC
Florida Power and Light (FPL)
Riviera Beach Energy Center
Plant Conversion Project

This project is not subject to prevention of significant deterioration (PSD) preconstruction review. Attached for your review are the following items:

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

This draft permit is to construct one nominal 1,250 megawatts (MW) combined cycle unit and ancillary equipment at the FPL Riviera Beach Energy Center previously known as the Riviera Plant. Two existing steam generators designated with a total nominal capacity of 600 MW will be shut down and dismantled as part of this project.

I recommend your approval of the attached Draft Permit.

Attachments

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

April 17, 2009

Electronically Sent – Received Receipt Requested

Randall_LaBauve@fpl.com
Mr. Randall R. LaBauve, Vice President
Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Re: DEP File No. 0990042-006-AC
FPL Riviera Beach Energy Center
Conversion Project

Dear Mr. LaBauve:

On February 13, 2009, FPL submitted an air permit application to construct a nominal 1,250 megawatts (MW) natural gas-fueled combined cycle unit and to shut down and dismantle the two 300 MW residual oil and gas-fueled units at the Riviera Plant. Enclosed are the following documents:

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

The Public Notice 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 the Project Engineer, Teresa Heron, at (850) 921-9529 or A. A. Linero, Program Administrator at (850) 921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/aal/th

Enclosures

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

DEP File No. 0990042-006-AC
FPL Riviera Beach Energy Center
Plant Conversion Project

PROJECT DESCRIPTION

This permit authorizes the construction of one nominal 1,250 megawatts (MW) combined cycle unit and ancillary equipment at the FPL Riviera Beach Energy Center (RBEC) previously known as the Riviera Plant. Two existing steam generators designated with a total nominal capacity of 600 MW will be shut down and dismantled as part of this project. The key components of the combined cycle unit are: three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors; three maximum 460 million Btu per hour, lower heating value (mmBtu/hr, LHV), natural gas-fueled duct burners (DB) located in the three HRSG (one DB per HRSG); three 149-feet exhaust stacks; and one common nominal 500 MW steam-electrical generator.

Pollution control measures include incorporation of combustion controls, inherently clean fuels, wet injection and selective catalytic reduction. The following emission limits provide assurance that the RBEC will comply with applicable requirements and will not result in a significant increase in emissions of any PSD-pollutant.

Pollutant	Fuel	Method of Operation	Initial Stacks Tests		CEMS Rolling Average Limit
			ppmvd	lb/hr	ppmvd
CO	Oil	CTG	10.0	61.0	10.0, 30 unit operating days
	Gas	CTG & DB	7.6	52.7	7.5, 30 unit operating days
		CTG Normal Mode	5.0	29.0	
NO_X	Oil	CTG	8.0	80.0	8.0, 30 unit operating days
	Gas	CTG & DB	2.0	22.8	2.0, 30 unit operating days
		CTG Normal Mode	2.0	19.3	
VOC	Oil	CTG	6.0	18.9	NA
	Gas	CTG & DB	1.9	7.2	
		CTG Normal Mode	1.5	4.8	
NH_3	Oil/Gas	CTG, All Modes	5	NA	NA
SAM/SO_2	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
PM/PM_{10}			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		

Emissions from the ancillary equipment including engines, small boilers, generators and process heaters will be controlled by use of clean fuels and adherence to the respective New Source Performance Standards or National Emissions Standards for Hazardous Air Pollutants as applicable. Based on the ambient impact analyses conducted, there is reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

4/13/09

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

Florida Department of Environmental Protection
Division of Air Resources Management, Bureau of Air Regulation
2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400

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

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408
Authorized Representative: Randall R. LaBauve

DEP File No. 0990042-006-AC
FPL Riviera Beach Energy Center
Conversion Project
Palm Beach County

Facility Location: The applicant, FPL, operates the existing Riviera Plant (RP), which is located in Palm Beach County at 200-300 Broadway, Riviera Beach.

Project: FPL proposes to construct a nominal 1,250 megawatts (MW) natural gas-fueled combined cycle unit and to shut down the two 300 MW residual oil and gas-fueled units at the existing RP. The RP will be renamed the Riviera Beach Energy Center (RBEC). This project does not trigger a prevention of significant deterioration (PSD) review and a determination of best available control technology (BACT) is 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 construction permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, Mail Station (MS) 5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

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

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

Notice of Intent to Issue Air Construction Permit: The Permitting Authority gives notice of its intent to issue an air construction permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

The Permitting Authority will issue a final air construction permit in accordance with the conditions of the proposed draft air construction permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

This permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

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

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

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

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

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Construction Permit package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Air Construction Permit) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested on 4/17/09 to the persons listed below.

Randall R. LaBauve: randall_labauve@fpl.com
Chair, Palm Beach Board of County Commissioners: agreene@co.palm-beach.fl.us
Mayor, Rivera Beach through the City Clerk: cclerk@rivierabch.com
Mayor, Palm Beach: jmcdonald@townofpalmbeach.com
Mayor, West Palm Beach: lfrankel@wpb.org
Mayor, Mangonia Park through the Town Clerk: salbury@townofmangoniapark.com
Mayor, Palm Beach Shores: tmills@pbstownhall.org
Mayor, Lake Park through the Town Clerk: townclerk@lakeparkflorida.gov
Heather Abrams, EPA: abrams.heather@epa.gov
Katy Forney, EPA: forney.kathleen@epa.gov
Dee Morse, U.S. National Park Service: dee_morse@nps.gov
Jack Long, DEP SED: jack.long@dep.state.fl.us
Lennon Anderson, DEP SED: anderson.lennon@dep.state.fl.us
Mike Halpin, DEP Siting: mike.halpin@dep.state.fl.us
Jim Stormer, Palm Beach County Public Health Unit: james_stormer@doh.state.fl.us
Barbara Linkiewicz, FPL: barbara_p_linkiewicz@fpl.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Victoria Gibson (read file), DEP BAR: victoria.gibson@dep.state.fl.us

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 4/17/09 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0990042-006-AC
Florida Power and Light Company (FPL)
Riviera Conversion Project
Palm Beach County

Applicant: The applicant for this project is FPL. The applicant's authorized representative and mailing address is: Mr. Randall R. LaBauve, Vice President, FPL, 700 Universe Boulevard, Juno Beach, Florida 33408.

Facility and Location: FPL operates the existing Rivera Plant (RP), which is located in Palm Beach County at 200-300 Broadway, Riviera Beach. The plant is located approximately 120 kilometers (km) north of the Prevention of Significant Deterioration (PSD) Class I Everglades National Park. The facility UTM coordinates are Zone 17, 594.249 km East and 2960.632 km North. The existing facility consists of two residual fuel oil and gas-fueled steam electrical generators.

Project: FPL proposes to construct a nominal 1,250 megawatts (MW) natural gas-fueled combined cycle unit and to shut down and dismantle the two 300 MW residual oil and gas-fueled units (and their 298-foot exhaust stacks) at the existing RP. The RP will be renamed the Riviera Beach Energy Center (RBEC). This project does not trigger PSD and a determination of best available control technology (BACT) is not required.

Combined Cycle Unit 5 will consist of: three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) equipped with selective catalytic reduction (SCR) reactors and duct burners (DB); three 149 foot exhaust stacks; and a common nominal 500 MW steam turbine-electrical generator (STG).

Additional equipment includes: a small auxiliary boiler; two diesel-fueled emergency generators; two natural gas fired fuel heaters; one diesel-fueled fire pump engine; a fuel oil storage tank; and a natural gas-fueled gas compression station.

The RBEC will be permitted to operate continuously while firing inherently clean natural gas. Use of ultra low sulfur distillate (ULSD) fuel oil (0.0015 percent sulfur) will be allowed as backup fuel up to the fuel equivalent of 2,550 hours aggregated over the three CTG during any calendar year. The gas-fired DB located within each HRSG will be used for limited periods of time to raise additional steam for use in the STG.

There will be very substantial decreases in the regulated air pollutants except for volatile organic compounds (VOC). The maximum potential annual emissions from the new units in tons per year (TPY) are summarized below for comparison with recent annual emissions from the two units slated for shut down.

Pollutant	RP Baseline Actual Emissions TPY	RBEC Potential Emissions TPY	Net Emissions Increases (Decreases) TPY
Sulfur Dioxide (SO_2)	10,999	210	(10,789)
Particulate Matter (PM/PM_{10})	889/889	188/188	(701)/(701)
Nitrogen Oxides (NO_X)	3,752	498	(3,254)
Carbon Monoxide (CO)	560	529	(31)
Volatile Organic Compounds (VOC)	59.4	99.1	39.7
Sulfuric Acid Mist (SAM)	489	42	(447)
Lead (Pb)	0.12	0.05	(0.07)

(Public Notice to be Published in the Newspaper)

SCR systems with ammonia injection will be used in conjunction with Dry Low-NO_X combustion to control NO_X emissions when operating on natural gas. The SCR systems will also be used in conjunction with wet injection when firing back up ULSD. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emission limits are included in the draft permit that are comparable with BACT. The limits further insure that the indicated emission reductions will be achieved and that the individual units comply with the respective requirements pursuant to the Standards of Performance for New Stationary Sources pursuant to 40 Code of Federal Regulations, Part 60. Emissions of CO and NO_X will be continuously monitored to demonstrate compliance with the conditions of the permit.

Because of the substantial emission reductions, the project did not trigger PSD and an ambient air quality impact analysis including PSD increment consumption modeling was not required. However, the applicant conducted ambient air modeling that demonstrates that (even with the lower stacks) facility operations will continue to comply with the ambient air quality standards (AAQS).

The lower NO_X emissions will reduce ozone (smog) formation potential and nitrate fallout into local watersheds. The lower PM/PM_{10}, SO_2 and SAM emissions will significantly reduce visible stack emissions, acid deposition, and fine particulate ($PM_{2.5}$) formation in the environment. The overall impacts due to the project are all favorable. There will also be reductions of hazardous air pollutants (HAP) such as nickel (Ni) with the result that the RBEC (in contrast to the RP) will not be a major source of HAP.

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 construction permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, Mail Station (MS) 5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

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

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

Notice of Intent to Issue Air Construction Permit: The Permitting Authority gives notice of its intent to issue an air construction permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

The Permitting Authority will issue a final air construction permit in accordance with the conditions of the proposed draft air construction permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

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

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

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

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

Mediation: Mediation is not available in this proceeding.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company (FPL)
Riviera Beach Energy Center

Riviera Plant Conversion Project
Construction of one Nominal 1,250-Megawatt (MW) Combined Cycle Unit
Shutdown and Dismantlement of two Residual Oil and/or Gas-fueled Steam Generating Units

Palm Beach County

DEP File No. 0990042-006-AC

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation

April 17, 2009

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

Processing Schedule

- February 13, 2009: Received Air Construction Permit Application
- March 13, 2009: Department sent request for additional information (RAI) to FPL
- April 13, 2009: Received electronic mail summarizing resolution of issues in RAI
- April 17, 2009: Preliminary Determination Issued

Facility Description and Location

FPL proposes to shut down and dismantle the two 300 MW residual oil and/or gas-fueled steam generating units and to construct a nominal 1,250 MW natural gas-fueled combined cycle unit at the Riviera Plant (RP) site. The RP site will be renamed the Riviera Beach Energy Center (RBEC).

The RP location is at 200-300 Broadway, Riviera Beach in Palm Beach County. The location with respect to other FPL facilities in Florida is shown in Figure 1. The plant is bounded on the east by the Intracoastal Waterway. Figure 2 is an aerial view of the existing RP taken from the southwest.

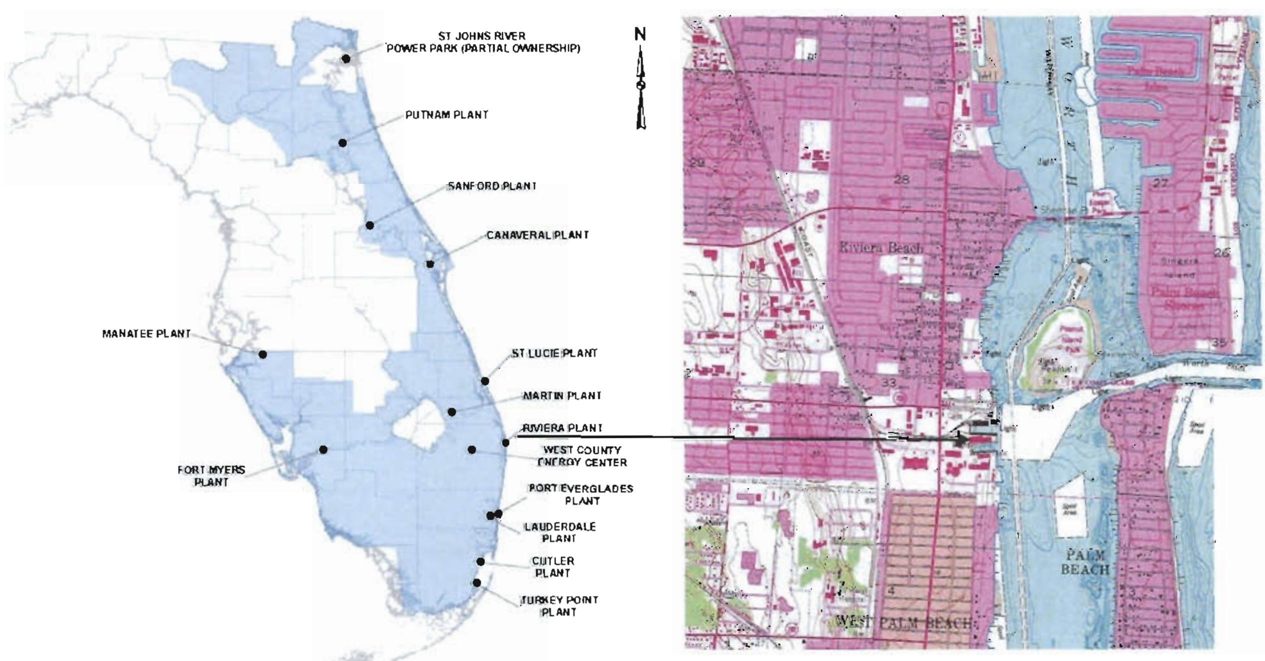

Figure 1. Riviera Plant in FPL System and Location of Plant in Palm Beach County.

The plant is located approximately 120 kilometers (km) north of the Prevention of Significant Deterioration (PSD) Class I Everglades National park and 326 km southeast of the Class I Chassahowitzka National Wilderness Area. The facility UTM coordinates are Zone 17, 594.249 km East and 2960.632 km North.

REGULATORY CLASSIFICATION

The RP is a "Major Stationary Source" as defined in Rule 62-210.200, Florida Administrative Code (F.A.C.). The RBEC project does not trigger the rules for the Prevention of Significant Deterioration (PSD) pursuant to Rule 62-212.400, F.A.C. and does not require a best available control technology (BACT) determination.

The RBEC will be a Title V or "Major Source" of air pollution in accordance with Chapter 213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

The RBEC will be subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS).

Unit 5 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also applies to duct burners (DB) that are incorporated into combined cycle projects.

Emergency generators and a diesel fire pump will be subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines.

Natural gas compressors will be subject to 40 CFR 60, Subpart JJJJ – NSPS for Stationary Spark Ignition Internal Combustion Engines.

A temporary natural gas-fueled boiler will be subject to 40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units.

An auxiliary boiler and process (fuel) heaters will be subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial-Commercial-Institutional Steam Generating Units.

The RBEC will be a minor (area source) of hazardous air pollutants (HAP). The RBEC will include emission units that will be subject to certain area source provisions of 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP).

Natural gas compressors will be subject to 40 CFR 63, Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE).

The RBEC will operate units subject to the Title IV Acid Rain provisions of the Clean Air Act (CAA).

The RBEC is subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The project is subject to certification under the Florida Power Plant Siting Act, 403.501-518, Florida Statutes (F.S.) and Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The two existing 300 MW steam generating units will be shut down and then dismantled prior to construction of the RBEC and by December 31, 2012. There will be no overlap of operation between the existing units and the new proposed units, which are anticipated to have an in-service date of June 2014.

The RBEC project includes the construction of a natural gas-fueled 3-on-1 combined cycle unit with a nominal rating of 1,250 megawatts (MW) referenced to International Standards Organization (ISO) conditions of 59 °F and standard humidity and pressure. The combined cycle Unit 5 will consist of: three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems and a common nominal 500 MW steam turbine-electrical generator (STG); three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors and a maximum 460 million Btu/hour, lower heating value (mmBtu, LHV), gas-fired DB with three 149 foot exhaust stacks.

FPL is considering three different models of the Mitsubishi Power Systems (MPS) G Class CTG. These include the MPS 501G1, the MPS 501G1+, and the MPS 501G3. FPL is also considering the recently developed Siemens H CTG. The latter would need to be resized (from the European version) and optimized for the 60-hertz (Hz) U.S. market. The final rating of the selected MPS or Siemens model will be between 250 and 280 MW at ISO depending upon the model selected.

Additional ancillary equipment will include:

- One nominal 85,000 pounds of steam per hour (lb/hr) auxiliary boiler;
- Two nominal 10 mmBtu/hr natural gas fired fuel heaters (one is a spare);
- Seven nominal natural gas-fueled gas compressors, each rated at approximately 1,340 hp;
- Two nominal 2,250 kilowatts (kW) diesel-fueled emergency generators;
- One nominal 300 horsepower (hp) diesel-fueled fire pump engine;
- One nominal 6.3 million distillate fuel oil storage tank; and
- One nominal 110 mmBtu/hr boiler for the construction phase.

Following is a listing of the new emissions units for the proposed project.

ID	Emission Unit Description
007	Unit 5A – one nominal 265 MW CTG with supplementary-fired HRSG
008	Unit 5B – one nominal 265 MW CTG with supplementary-fired HRSG
009	Unit 5C – one nominal 265 MW CTG with supplementary-fired HRSG
010	One nominal 85,000 pounds per hour (lb/hr) auxiliary boiler (99.8 mmBtu/hr)
011	Two nominal 10 mmBtu/hr gas-fired process heaters (one is a spare)
012	Seven nominal 1,340 hp natural gas compressors
013	Two nominal 2,250 kW emergency generators
014	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank
015	One 110 mmBtu/hr boiler to be used only under the construction phase
016	One nominal 6.3 million distillate fuel oil storage tank

Following are additional project characteristics.

- Fuels: Each CTG will fire natural gas as the primary fuel and ultra low sulfur diesel (0.0015% sulfur) fuel oil (ULSD FO) as a restricted alternate fuel. The applicant proposes to fire ULSD FO up to the fuel equivalent 2,550 hours aggregated over the three CTG during any calendar year.
- Generating Capacity: Each of the three CTG has a nominal generating capacity of 265 MW. Each of the three HRSG provides steam to the single STG, which has a nominal capacity of 500 MW. The nominal capacity of Unit 5 will be 1,250 MW.

- Controls: CO, PM/PM_{10}/$PM_{2.5}$ and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ULSD FO. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and wet injection (WI) for oil firing. In combination with these NO_X controls, a SCR system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: Each CTG is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain emission limits that insure the project will not be a major stationary source modification with respect to the PSD rules. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: Each HRSG has a combined cycle stack that is at least 149 feet tall with a nominal diameter of 22 feet. The following table summarizes the nominal exhaust characteristics of a representative CTG/HRSG set, exclusive of the DB:

Table 1. Exhaust Characteristics of the CTG comprising Unit 5 at 100% Load and 59 °F

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp., °F	Exhaust Temp., °F	Flow Rate ACFM
Gas	2,586 mmBtu/hour *	59 °F	195 °F	1,388,967
Oil	2,440 mmBtu/hour *	59 °F	357 °F	1,677,310

* The Department will set a maximum heat input rate at a higher value in the expectation that the delivered products may achieve a greater (or lower) heat input rate than the nominal value.

The following figure includes an aerial photograph from the FPL website of the two existing steam generating units and their 298-foot stacks taken from southwesterly direction. The other graphic is an artist rendition of the combined cycle unit after dismantling of the existing stacks and units and completion of the proposed project.

Figure 2. FPL Riviera Units 1 and 2. Artist Rendition of New Combined Cycle Unit

The shut down and dismantlement of the two units will be quite noticeable as they are presently allowed to be fueled by up to 2.5 percent (%) sulfur residual fuel oil augmented by natural gas. Also, the existing units are subject to a 40% visible emissions (VE) standard and are allowed even greater opacity during soot blowing. By contrast, the new unit will use inherently clean fuels and will typically exhibit zero VE.

Process Description

A CTG is an internal combustion engine that operates with rotary rather than reciprocating motion and that is coupled to an electrical generator. A representative longitudinal section diagram of a CTG, in this case for a MPS 501G (rotor inside of casing) from a MPS brochure, is shown in the left hand side of the figures below. The photograph on the right hand side of the figure is of a Siemens H-Class CTG that is undergoing validation testing in Germany. The view is from the rotor section looking into the combustor section (without the cans). A similar product but smaller product will be developed for the 60 megahertz U.S. market.

Ambient air is drawn into the multistage compressor of the CTG where it is compressed to a very high pressure ratio. The compressed air is then directed to the combustor section, which consists of individual steam-cooled, can-annular, DLN combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is greater than 2,700 °F.

Figure 3. Longitudinal View of MPS 501G, Siemens "H" Class CTG (MHI, Siemens Websites)

The hot combustion gases routed through the steam-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. Energy is recovered in the turbine 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 unit such as an electrical generator. Turbine exhaust gas (TEG) is discharged at a temperature greater than 1,125 °F and contains more than 10% oxygen (O_2). The TEG is available for additional energy recovery and can also support further combustion.

Each CTG/HRSG set will operate in combined cycle mode as depicted in Figure 4. The TEG from each CTG will raise additional steam in each HRSG. The steam from the three HRSG will, in-turn, drive a single, separate STG producing additional electrical power.

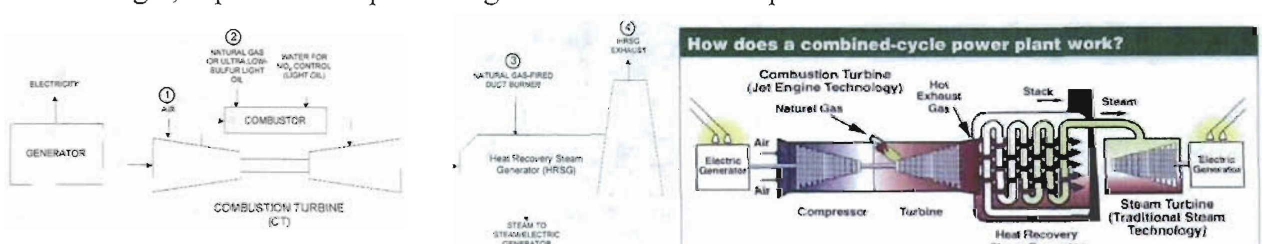

Figure 4. Natural Gas Fueled Combined Cycle Unit with DB and Backup ULSD FO

In combined cycle mode, the thermal efficiency of the most modern MPS G-Class CTG is approximately 58 percent (%) on the basis of LHV and about 53% based on the higher heating value (HHV). The Siemens H-Class CTG is expected to achieve approximately 60% thermal efficiency on the basis of LHV.

- Inlet Conditioning: Evaporative cooling is the injection of fine water droplets into the CTG compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a higher mass flow rate through the CTG with a boost in electrical power production. The emissions performance remains within the normal profile of the CTG for the lower compressor inlet temperatures. This is typically implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired DB can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2,880 hours of duct burning per year for each HRSG.

3. RULE APPLICABILITY

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 Florida Administrative Code.

Table 2. Key Applicable State Regulations

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
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	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Federal Regulations

This project is also subject to the following federal provisions regarding air quality as established by the U.S. Environmental Protection Agency (EPA) in the CFR.

Table 3. Key Applicable Federal Regulations

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions
Part 96	NO_X Budget Trading Program for State Implementation Plans

Description of PSD Non-Applicability

The Department regulates major air pollution sources in accordance with Florida's PSD program, as described in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant.

The RP is a Major Stationary Source with respect to the PSD Rules because it is a fossil fuel-fired steam electric plant of more than 250 million Btu heat input and has the potential to emit 100 tons per year or more of a PSD pollutant.

The RBEC Project is not a Major Modification of a Major Stationary Source because there will not be a net emissions increase greater than the significant emission rate (SER) of a PSD pollutant. The SER means a rate of pollutant emissions that would equal or exceed: 100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC; 25 TPY of particulate matter (PM); 15 TPY of PM smaller than 10 microns (PM_{10}); 7 TPY of SAM; or 0.6 TPY of lead (Pb).

Estimates of Net Emissions Changes

The new combined cycle unit will result in emissions of CO, NO_X, SO_2, PM/PM_{10}, SAM and VOC. The shut down and dismantlement of the two residual oil- and/or gas-fueled steam generating units will result in net emission changes of the same pollutants that are less than the SER.

The following table is a summary of the emissions increases and decreases from the proposed RBEC project to determine which pollutants will be emitted in excess of their respective SER.

Table 4. Applicant's Summary of Net Emissions Changes and PSD Applicability for the FPL RBEC Project.

Pollutant	RP Baseline Emissions TPY	RBEC Potential Emissions TPY	Net Emissions Increases (Decreases) TPY	PSD SER TPY	PSD?
SO_2	10,999	210	(10,789)	40	No
PM/PM_{10}	889/889	188/188	(701)/(701)	25/15	No
NO_X	3,752	498	(3,254)	40	No
CO	560	529	(31)	100	No
VOC	59.4	99.1	39.7	40	No
SAM	489	42	(447)	7	No
Lead	0.12	0.05	(0.07)	0.6	No
HAP	>25	<20	(≥ 5)	Not applicable (NA)	NA

Although no historical estimates of HAP are provided, the RP is a major source of HAP according to previous applications submitted by FPL and permits issued by the Department. The switch from residual fuel oil to inherently clean fuels through the RBEC project will reduce emissions of nickel (a HAP) and vanadium (V, not classified as a HAP) that tend to catalyze the oxidation of SO_2 to SAM. The future RBEC will not be a major source of HAP.

4. DRAFT OF EMISSIONS STANDARDS

4.1 NO_X Emissions Standard

NO_X Formation

NO_X forms in the CTG combustion process as a result of the dissociation of molecular nitrogen and oxygen 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 5.

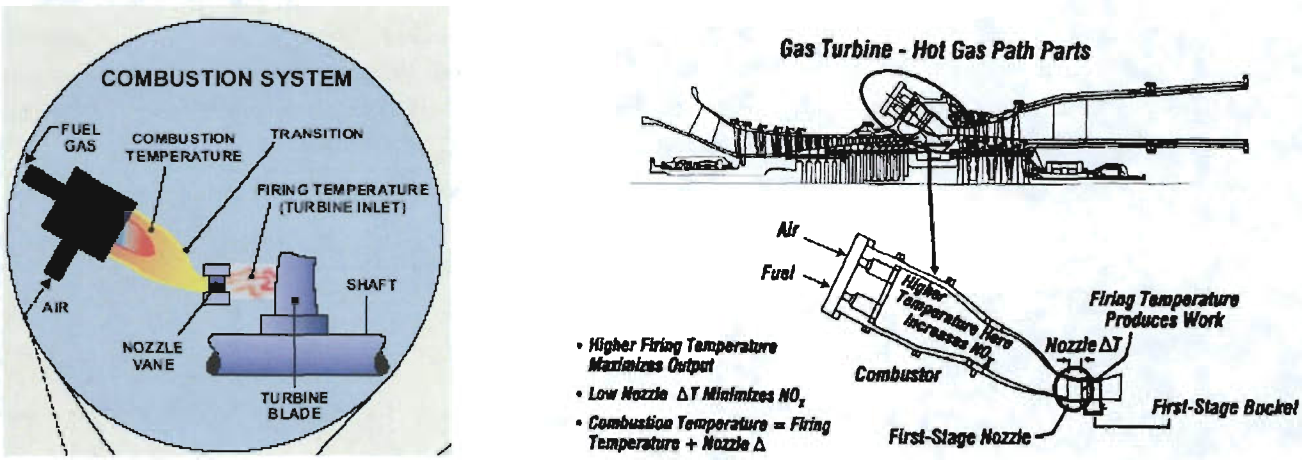

Figure 5. Relation between Combustion and Firing Temperatures and NO_X Formation

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 5, 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.

Uncontrolled emissions can range from about 100 to over 600 parts per million by volume, dry, corrected to 15% O_2 (ppmvd @15% O_2) depending upon design. The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 from the CTG chosen for this project.

Descriptions of Available NO_X Controls

Diluent Injection: WI. Injection of either water or steam as a diluent directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the CTG.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing WI for backup ULSD FO firing. WI results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below.

CO and VOC emissions are relatively low for most CTG. However, WI may increase emissions (water more than steam) of both of these pollutants.

Combustion Controls: DLN. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones. These principles are incorporated into the M501G DLN combustor (the Siemens H DLN combustor would be similar) shown on the left hand side of Figure 6. There is a central diffusion pilot nozzle that provides stability but ultimately limits the ability of the combustor to achieve the lowest possible NO_X emissions without further control.

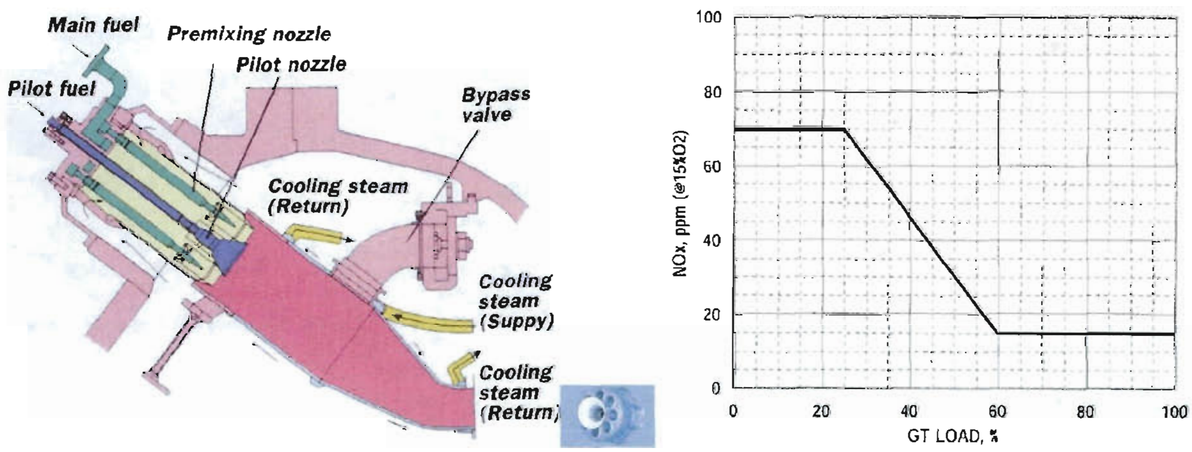

Figure 6. M501G DLN Combustor, Nozzle Block and NO_X versus Load Specification

The graph on the right hand side in Figure 6 contains the NO_X specifications for new Mitsubishi M501G1 CTG. The combustor emits NO_X at concentrations less than 15 ppmvd at loads between 60 and 100 percent of capacity. The firing temperature within the 60-100% load range is between roughly 2500 and 2750 °F. The low NO_X values are an excellent achievement considering the high firing temperature.

The difference between combustion temperature and firing temperature into the first stage is minimized by steam cooling of the transition piece and first stage nozzle. Thus a lower combustion temperature (and lower NO_X) can be achieved by steam cooling compared with air cooling for a given firing temperature (equal work). Alternatively, a higher firing temperature (more work, greater efficiency) can be achieved by steam cooling compared with air cooling for a given combustion temperature (equal NO_X).

The combustor for the M501G can probably achieve low NO_X emissions (< 20 ppm) at lower load than suggested by the diagram. The tendency to increase NO_X concentrations is mitigated by decreasing firing temperature.

Selective Catalytic Reduction (SCR). SCR is an add-on NO_X control technology that is employed in the exhaust stream following the CTG. SCR reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas in the presence of a catalyst. 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:

The left hand side of Figure 7 (Nooter-Eriksen) below 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.

The right hand side of Figure 7 is a photograph of the FPL West County Energy Center (WCEC) Unit 1 Power Block. The external lines to the NH_3 injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

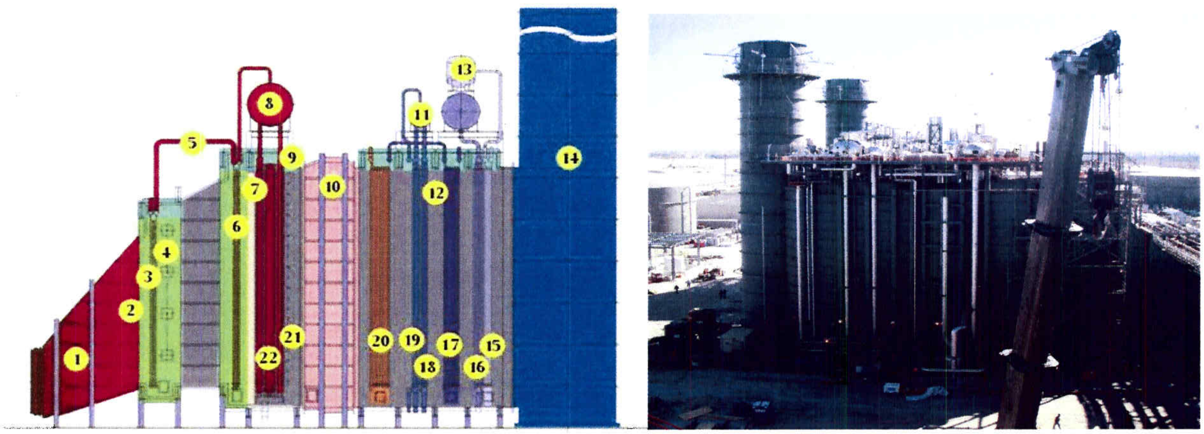

Figure 7 – Key HRSG Components (10 is SCR), FPL West County Energy Center Unit 1

The 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.

Applicant's NO_X Emissions Standard Proposal

The applicant proposes a NO_X limit of 2.0 ppmvd @15% O_2 for Unit 5 as a 30-unit operating day rolling average with compliance by CEMS whether or not the DB are in use. FPL proposes to meet the emission limit while burning natural gas by a combination of DLN technology and SCR. FPL proposes a NO_X emission limit of 8 ppmvd @15% O_2 by a combination of wet injection and SCR while burning backup ULSD FO. The corresponding standards pursuant to 40 CFR 60, Subpart KKKK are 15 and 42 ppmvd @15% O_2, on a 30-unit operating day rolling basis.

Department's Draft NO_X Emissions Standard Determination

The applicant's proposed limits are acceptable to the Department. These limits will insure compliance with Subpart KKKK and that the RBEC project will not trigger PSD and a BACT determination.

4.2 CO and VOC Emissions Standard

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from CTG due to incomplete fuel combustion. Most CTG incorporate good combustion to minimize emissions of CO and VOC. The primary control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of an oxidation catalyst.

The figure below contains CO specifications for the M501G while firing natural gas and FO, including the guarantee values that apply between 60 and 100%.

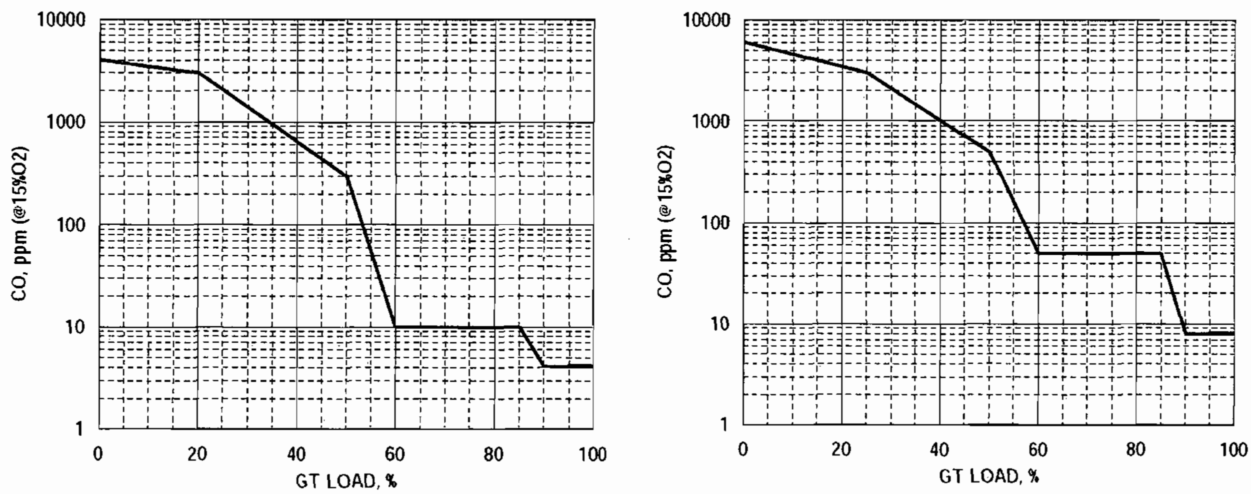

Figure 8. Expected CO versus Load while burning Gas or FO in a M501G

Generally the performance data on the left hand side indicate that the combustor performs very well on natural gas within the range of 60 to 100% of full load. At 60% of full load the flame and firing temperatures are great enough to destroy almost all CO. The graph on the right shows the characteristics while firing FO.

Typically, VOC concentrations are an order of magnitude less than CO concentrations. Therefore, while burning natural gas, VOC emissions will likely be less than 1 ppm while operating between 60 and 100% of full load. Similarly, VOC emissions less than 5 ppm and as low as 1 ppm are expected while firing FO.

DB and FO Considerations

The presence of a DB (refer to Figure 7, Component 4) complicates the evaluation somewhat. Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,200 °F) and high excess air (> 12% O_2). In the design shown in Figure 7, some of the heat is used by a high pressure superheater (Component 3). The gas-fired DB (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6). Figure 9 shows an individual burner and an array comprising a DB. The hot TEG serves as combustion air for gas introduced into the burner array.

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions are present to minimize further CO and VOC concentration increases when corrected to 15% oxygen.

Figure 9 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

CO emissions while firing FO should be very low, again, based on the high combustion temperature and the relatively high temperature and excess air in the TEG.

FPL's CO and VOC Emissions Standard Proposal

FPL has proposed emission limits for CO, VOC and $PM/PM_{10}/PM_{2.5}$ as the use of good combustion controls while firing natural gas or ULSD FO in accordance with the defined operating hours for each fuel. FPL proposes the emissions limits given in Table 5 for CO and VOC to account for all of the scenarios discussed above.

Table 5. FPL Emission Standard Proposal for CO, VOC – RBEC Project (ppmvd@15% O_2)

Modes (at full load)	CO	VOC
Natural Gas	5.0	1.5
Natural Gas & DB	7.6	1.9
ULSD FO	10.0	6.0

The emission estimates for the G and H technology options are similar with the exception of VOC when firing ULSD FO. The H technology CTG is estimated by the applicant to emit 2.0 ppmvd @15% O_2, whereas the estimate for the G technology CTG is 6.0 ppmvd @15% O_2.

Department's Draft CO and VOC Emissions Standard Determination

FPL initially requested annual compliance tests to demonstrate compliance with the standards given above. However, to provide reasonable assurance that that the RBEC project will not trigger PSD for CO, the Department determined that CEMS are required and that a 30-unit operating day rolling average is appropriate.

The Department will set a CO limit of 7.5 ppmvd @15% O_2 for Unit 5 as a 30-unit operating day rolling average with compliance by CEMS while firing natural gas whether or not the DB are in use. The main consideration for this value is the medium load performance (60 to 85% of full load) as shown in Figure 8 above. The Department will set a similarly based CO emission limit of 10 ppmvd @15% O_2 while burning backup ULSD FO. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds.

A permit condition will require that FPL shall design and build the project to facilitate possible future installation of an oxidation catalyst system to control CO emissions from each CTG/supplementary-fired HRSG.

The requested limit of 6.0 ppmvd VOC @15% O_2 is sufficient to insure there will not be a significant increase of VOC from the RBEC if firing of ULSD FO is limited to the fuel equivalent of 2,550 hours aggregated over the three CTG during any calendar year.

Recent data obtained during compliance testing of Turkey Point Combined Cycle Unit 5 indicated total hydrocarbon [THC-a more conservative measure of VOC)] emissions that are less than 0.2 ppmvd. Because Turkey Point Combined Cycle Unit 5 is an F-technology unit (with a lower firing temperature) one would expect VOC and CO emissions from G or H-technology units that are less than those from the F-technology unit.

According to additional information provided by Mitsubishi, VOC emissions will likely be less than 1 ppmvd @15% O_2 if CO emissions are less than 10 ppmvd @15% O_2. If VOC emissions are actually demonstrated to be as low as expected, FPL intends to apply for an increase in the allowable hours of ULSD FO to 3,000 hours aggregated over the three CTG during any calendar year.

After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the limit of 7.5 ppmvd CO @15% O_2 will provide additional long term assurance of compliance with the VOC limit and insure annual emission increases will be much less than the potential-to-emit estimated by FPL of 39.7 TPY.

4.3 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions Standard

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for CTG contained in the BACT Clearinghouse shows that the exclusive use of low sulfur (S) fuels constitutes the top control option for SO_2.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed the use of ULSD FO (0.0015 percent S) and clean natural gas with a sulfur fuel specification less than or equal to 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF).

FPL estimated 210 tons per year of SO_2 and 42 tons per year of sulfuric acid mist (SAM) for RBEC Unit 5. Realistically, annual emissions will be approximately one-fourth of the estimated values because the sulfur concentration in the pipeline gas is typically closer to 0.5 gr/100 SCF than to 2 gr/100 SCF.

<u>Department's Draft SO_2 Emissions Standard Determination</u>

The Department accepts FPL's emission limit proposal for SO_2 and SAM.

The Subpart KKKK Limit for SO_2 is 0.060 lb SO_2/mmBtu heat input. Compliance can be demonstrated by the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content is 0.05 weight percent or less for oil and less than 20 gr/100 SCF for gas. The applicant's sulfur emission standard proposal for this project will easily insure compliance with Subpart KKKK and that net SO_2 and SAM emissions increases will be less than the respective significant emission rates.

4.4 Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions Standard and Ammonia (NH_3) Control

PM/PM_{10} $PM_{2.5}$ Formation and Control Options

PM, PM_{10} and $PM_{2.5}$ will be emitted from the CTG and DB due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ULSD FO will be efficiently combusted at high temperature in the CTG and DB and will be the only fuels fired in the proposed unit. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ULSD FO to be combusted contains a minimal amount of ash and its use will be limited making any conceivable add-on control technique for $PM/PM_{10}/PM_{2.5}$ either unnecessary or impractical.

Other $PM/PM_{10}/PM_{2.5}$ Considerations

NH_3 Slip and Ammonium Salts Formation: Emissions of NO_X, SO_2, and SAM are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. These constituents form the fine PM that comprises $PM_{2.5}$. $PM_{10}/PM_{2.5}$ emissions can be increased due to the formation of these ammonium salts prior to exiting the stack or in the environment and contribute to regional haze. It is important to limit NH_3 emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of NH_3 slip can also be an indication of a degrading catalyst.

Applicant's $PM/PM_{10}/PM_{2.5}$ Proposal

FPL proposes $PM/PM_{10}/PM_{2.5}$ emissions standard as an opacity limit of 10% in conjunction with the use of inherently clean fuels.

Department's Draft $PM/PM_{10}/PM_{2.5}$ Emissions Standards

The following conditions are established as the draft emissions standards.

- The CTG shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The DB are limited to firing only natural gas meeting this specification. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. Fuel oil may be fired up to the fuel equivalent of 2,550 hours aggregated over the three CTG during any calendar year.
- VE shall not exceed 10% opacity based on a 6-minute average.
- NH_3 emissions (slip) shall not exceed 5 ppmvd.

4.5 Department Draft Emissions Standards for CTG and DB

Emissions from each CTG shall not exceed the values given in the following table.

Table 6. Draft Emissions Standards

Pollutant	Fuel	Method of Operation	Initial Stacks Tests		CEMS Rolling Average Limit
			ppmvd[a]	lb/hr[b]	ppmvd[a]
CO[d]	Oil	CTG	10.0	61.0	10.0, 30 unit operating days[c,d]
	Gas	CTG & DB	7.6	52.7	7.5, 30 unit operating days[c,d]
		CTG Normal Mode	5.0	29.0	
NO_X[e]	Oil	CTG	8.0	80.0	8.0, 30 unit operating days[c,e]
	Gas	CTG & DB	2.0	22.8	2.0, 30 unit operating days[c,e]
		CTG Normal Mode	2.0	19.3	
VOC[f]	Oil	CTG	6.0	18.9	NA
	Gas	CTG & DB	1.9	7.2	
		CTG Normal Mode	1.5	4.8	
NH_3[g]	Oil/Gas	CTG, All Modes	5	NA	NA
SAM/SO_2[h]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
PM/PM_{10}[i]			VE shall not exceed 10% opacity for each 6-minute block average.		

a. Concentration standards are given in terms of parts per million, by volume, dry at 15 percent oxygen and abbreviated as ppmvd.
b. The mass emission rate standards in pounds per hour (lb/hr) are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations filed with the Department.
c. "Unit operating day" means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period. [40 CFR 60.4420]
d. Compliance with the continuous 30-unit operating days rolling CO standard shall be demonstrated based on data collected by the required CEMS. The initial EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate initial performance guarantees for natural gas, oil, and DB mode.
e. Continuous compliance with the 30-unit operating days rolling NO_X standards shall be demonstrated based on data collected by the required CEMS and will also insure compliance with the less stringent Subpart KKKK limits of 15 and 42 ppmvd for gas and fuel oil respectively on a 30-unit operating day rolling average basis. The initial 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 natural gas, fuel oil, 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).
f. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required.
g. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.
h. The clean fuel sulfur specifications and VE standard effectively limit the potential emissions of SAM and SO_2 from the CTG. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
i. The clean fuel sulfur specifications, low CO and NO_X limits, and the VE standard will effectively limit $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the VE standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

4.6 National Emission Standards for Hazardous Air Pollutants Applicable to CTG

FPL estimates future HAP emissions from the RBEC at less than 20 TPY total and less than 10 TPY of a single HAP (formaldehyde). The Department accepts the estimates for this project based on combustor information indicating that formaldehyde emissions while burning fuel oil will be low (on the order of 0.05 ppm) if CO emissions are less than 10 ppmvd @15% O_2. As such, the proposed new CTG would not be subject to 40 CFR 63, Subpart YYYY.

4.7 Emission Standards for Boilers

Two small boilers are required for this project. The first is an auxiliary boiler rated at 99.8 mmBtu/hr that will be used less than 500 hours per year (hr/yr). The purpose of the auxiliary boiler is to provide steam for combustor cooling until steam of sufficient quality can be provided by the HRSG.

The second is a temporary boiler rated at 110 mmBtu/hr that will be removed by expiration date of the permit. It will also be used less than 500 hr/yr. The purpose of the temporary boiler is to provide steam to clean (such as by steam blows) construction activity residues from surfaces in the CTG, HRSG and STG construction.

The auxiliary boiler and temporary boiler are subject to 40 CFR 60, Subparts Dc and Db respectively. FPL has proposed and the Department accepts the following emission standards for the boilers. The requirements from Subparts Db and Dc are shown for comparison purposes.

Table 7. Applicant Proposal for SO_2, CO, NO_X, VOC, PM Standards – Boilers

Source	SO_2 (gas S spec.)	CO (lb/mmBtu)	PM/PM_{10} (lb/mmBtu)	VOC (lb/mmBtu)	NO_X (lb/mmBtu)
Temp. Boiler	2 gr S/100 SCF	0.08	0.007	0.005	0.050
Aux. Boiler					
Subpart Db	Not applicable (NA) for natural gas firing				0.20
Subpart Dc	Sources between 10 and 100 mmBtu/hr - record keeping required				

It is noted that the requirements of the applicable NSPS are minimal. Because of the large reductions in the emissions of all pollutants (except for CO) due to the project, limits for VOC, NO_X and PM/PM_{10} are not necessary for the auxiliary boiler. However the requested CO and NO_X limits will be reflected in the permit with reliance on the fuel specification and a VE standard for the rest.

4.8 Emissions Standard for Natural Gas Process Heaters

Two natural gas heaters rated at 10 mmBtu/hr are required for the project. One is designated as a spare. The purpose of these units is to heat natural gas above dew point temperature and prevent condensation. The gas heaters are subject to 40 CFR 60, Subpart Dc.

FPL has proposed and the Department accepts the following emission standards for the two natural gas heaters. The minimal requirement from Subpart Dc is shown for comparison purposes.

Table 8. Emission Standards for Emissions from Natural Gas-fired Fuel Process Heaters

Source	SO_2 (gas S spec.)	NO_X (lb/mmBtu)	CO (lb/mmBtu)	VOC (lb/mmBtu)	PM (lb/mmBtu)
Application	2 gr S/100 SCF	0.095	0.08	0.005	0.002
Subpart Dc	Sources between 10 and 100 mmBtu/hr - record keeping required				

The requested CO and NO_X limits will be reflected in the permit with reliance on the fuel specification and a VE standard for VOC, SO_2 and PM.

4.9 Emissions Standard for the Compressor Station

Seven natural gas compressors rated at 1,340 horsepower (hp) are required for the project. The compressors will have four-stroke, lean burn, spark ignition engines. These will be used to increase pressure from the existing Florida Gas Transmission (FGT) lateral pipeline to Unit 5. The gas compressors are subject to the requirements for non-emergency lean burn engines at 40 CFR 60, Subpart JJJJ.

FPL has proposed and the Department accepts the applicant's proposed emission standards for the seven compressors except that a more stringent NO_X standard may apply pursuant to Subpart JJJJ if the compressors are manufactured after July 1, 2010. The applicant's proposal and the requirements for such engines from Subpart JJJJ are shown in the following table.

Table 9. Emission Standards for Compressors - grams per horsepower-hour (g/hp-hr)

Source (manufacture date)	CO (g/hp-hr)	VOC (g/hp-hr)	NO_X (g/hp-hr)	PM (lb/mmBtu)	SO_2 (gas S spec.)	VE (opacity)
Compressors (application)	0.10	0.16	1.5	0.0099[a]	2 gr/100scf	10%
Subpart JJJJ (1/1/2008)	4.0	1.0	2.0	NA		
Subpart JJJJ (after 7/1/2010)	2.0	0.7	1.0			

a. 0.0099 lb/mmBtu equals approximately 0.034 g/hp-hr. Units in the permit will be expressed as g/hp-hr.

The specification given in the application would also meet the Subpart JJJJ NO_X requirement of a model year 2008 engine but not the NO_X requirement of an engine manufactured on or after July 1, 2010. Based on discussions between the Department and intended manufacturer, engines to meet the more stringent 7/1/2010 will be available. According to the application, the compressor engines will be equipped with oxidation catalysts and will thus be low CO and VOC emitters.

The requested VOC, CO and NO_X limits will be reflected in the permit with reliance on the fuel specification and a VE standard for the SO_2 and PM limit.

These compressors are Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart JJJJ.

4.10 Emissions Standard for Diesel Emergency Generators

Two standby diesel emergency generators rated at 2,250 kW (3,200 brake hp) are required for the project. These will be used when electricity is not available to the site, such as during hurricanes. The emergency generators are subject to 40 CFR 60, Subpart IIII.

FPL has proposed and the Department accepts the following emission standards for the two emergency generators. The identical requirements (except for fuel specification) from Subpart IIII for emergency generators constructed in 2007-2010 are shown for comparison purposes.

Table 10. Emission Standards for Diesel Emergency Generators.

Source (model year)	CO (g/hp-hr)	Hydrocarbons (HC) (g/hp-hr)	NO_X (g/hp-hr)	PM (g/hp-hr)	SO_2 (oil S spec.)	VE (opacity)
Application	8.5	1.0	6.9	0.4	0.0015	10%
Subpart IIII (2007-2010)	8.5	1.0	6.9	0.4	NA	
Subpart IIII (2011 & later)	2.6	4.8 Non-methane HC+ NO_X		0.15		

The permit will reflect the requirement to adhere to the appropriate Subpart IIII values and will include the requested ULSD fuel oil specification and VE limit. If the applicant selects a later model year (2011 or later), it will be necessary to adhere to the more stringent limitations given in Subpart IIII.

These diesel emergency generators are Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

4.11 Emissions Standards for Emergency Fire Pump Engines

One 300-horsepower (hp) fire pump engine is required for the project. It will be used sparingly and will fire ULSD fuel oil. The gas compressors are subject to 40 CFR 60, Subpart IIII.

FPL has proposed and the Department accepts the following emission standards for the fire pump engine. The requirements for such engines constructed in 2008 and in 2009 (and thereafter) from Subpart IIII are shown for comparison.

Table 11. Emission Standards for Emergency Fire Pump Engines.

Source (model year)	CO (g/hp-hr)	VOC (g/hp-hr)	NO_X (g/hp-hr)	PM (g/hp-hr)	SO_2 (oil S spec.)
Application	2.6	1.0	6.8	0.40	0.0015
Subpart IIII (2008)	2.6	7.8 ($NMHC^a+NO_X$)		0.40	NA
Subpart IIII (2009+)[b]	NA	3.0 ($NMHC+NO_X$)		0.15	

a. NMHC is the acronym for non-methane hydrocarbons. NMHC are approximately equal to VOC for these sources.

b. Model year 2009-2011engines with speed greater than 2,650 revolutions per minute (rpm) comply with model 2008 requirements. Fire pumps such as planned for the project typically exhibit much less than 2,650 rpm.

The permit will reflect the requirement to adhere to the appropriate Subpart IIII values (e.g. NMHC instead of VOC) and will include the requested ULSD fuel oil specification. If the applicant selects a model year of 2009 (or later), it will be necessary to adhere to the more stringent limitations of Subpart IIII.

5. PERIODS OF EXCESS EMISSIONS

5.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "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." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

5.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "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 two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "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." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed standards based on the given characteristics of the specific project.

During a cold startup of the STG system, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. The gradual warming of the HRSG and STG components is accomplished by operating the CTG for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from FPL regarding startup and shutdown, the Department establishes the following conditions for excess emission data exclusions from the 30-operating day state permit limits for the CTG/HRSG system. These exclusions cannot vary or supersede any federal provision of the New Source Performance Standards, or Acid Rain programs.

Excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, NO_X and CO emission data excluded from the 30-operating day rolling average calculations due to startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. *STG/HRSG System Cold Startup*: For cold startup of the steam turbine system, NO_X and CO emission data exclusions for any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

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

b. *Shutdown Steam Turbine System*: For shutdown of steam turbine system, NO_X and CO emission data exclusions for any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.

c. *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, NO_X and CO emission data exclusions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. *Fuel Switching*: For fuel switching, NO_X and CO emission data exclusions shall not exceed two (2) hours in any 24-hour period.

e. *Startup and Shutdown Opacity*: During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

For startup, NH_3 injection shall begin as soon as the system reaches the manufacturer's specifications. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The proposed RBEC project will not increase emissions of criteria pollutants at levels in excess of PSD significant emission rates (SER).

Although the proposed project is not PSD applicable, the applicant provided an air quality analysis to ensure that the conversion will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS).

6.2 Major Stationary Sources in Palm Beach County

The current largest stationary sources in Palm Beach County are listed below. The information is from annual operating reports submitted to the Department from 2007. The future estimates for the FPL RBEC that will replace the RP are included for comparison.

Table 12. Major Sources of NO_X in Palm Beach County

Owner	Site Name	Tons per year (TPY)
Florida Power & Light	**RP (will be shut down)**	**2,068**
Palm Beach County SWA	Resource Recovery Facility	1,153
Florida Power & Light	**WCEC – Under Construction**	**1,072**
New Hope Power Partnership	Okeelanta Cogeneration Plant	842
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	679
Florida Power & Light	**RBEC (future estimate)**	**498**

Table 13. Major Sources of SO_2 in Palm Beach County

Owner	Site Name	Tons per year
Florida Power & Light	**RP (will be shut down)**	**5,556**
Florida Power & Light	**WCEC – Under Construction**	**598**
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	500
Palm Beach County SWA	Resource Recovery Facility	269
New Hope Power Partnership	Okeelanta Cogeneration Plant	235
Florida Power & Light	**RBEC (future estimate)**	**210**

Table 14. Largest Sources of PM_{10} in Palm Beach County

Owner	Site Name	Tons per year
Florida Power & Light	**RP (will be shut down)**	**476**
Florida Power & Light	**WCEC – Under Construction**	**416**
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	357
Osceola Farms	Osceola Farms	270
Florida Power & Light	**RBEC (future estimate)**	**188**
US Sugar Corporation	Bryant Sugar Mill	156

Table 15. Largest Sources of CO in Palm Beach County

Owner	Site Name	Tons per year
Osceola Farms	Osceola Farms	11,026
U.S. Sugar Corp.	Bryant Mill	7,219
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	2,250
New Hope Power Partnership	Okeelanta Cogeneration Plant	1,975
Florida Power & Light	**WCEC – Under Construction**	**1,559**
Palm Beach County SWA	Resource Recovery Facility	743
Florida Power & Light	**RBEC (future estimate)**	**529**
Florida Power & Light	**RP (will be shut down)**	**526**

Table 16. Largest Sources of VOC in Palm Beach County

Owner	Site Name	Tons per year
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	640
Osceola Farms	Osceola Farms	539
U.S. Sugar Corp.	Bryant Mill	423
Florida Power & Light	**WCEC – Under Construction**	**247**
Florida Power & Light	**RBEC (future estimate)**	**99**
New Hope Power Partnership	Okeelanta Cogeneration Plant	78
Florida Power & Light	**RP (will be shut down)**	**51**

6.3 SO_2 and NO_X Trends from FPL Peninsular facilities

To put the emissions from the existing RP and the future RBEC into the larger perspective, the Department graphed the SO_2 and NO_X emission trends during the period 1998-2007 from FPL fossil-fueled plants located in the Florida peninsula. The data source is the EPA Clean Markets Acid Rain database. The results are summarized in Figure 10.

During the period 1998-2007 there was a *decrease* from 221,400 to 50,900 TPY (77%) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* from 98,500 to 31,800 TPY (68%) in NO_X emissions. Some of these reductions occurred at the RP.

There will be approximately 5,500 TPY of further reductions in SO_2 and approximately 2000 TPY of further reduction in NO_X due to the shut down and dismantlement of the RP and replacement with the RBEC. For comparison purposes, the future RBEC will emit a little more than 200 TPY of SO_2 and 500 TPY of NO_X.

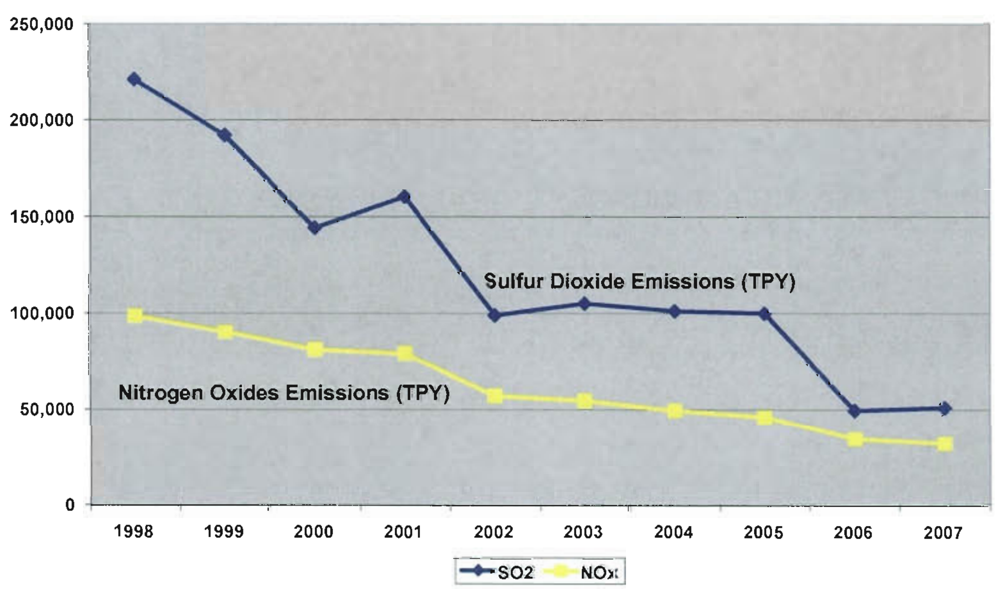

Figure 10 – SO_2 and NO_X reductions at FPL peninsular facilities (1998-2007)

6.4 Air Quality and Monitoring in the Palm Beach County

The Palm Beach County Health Department operates nine monitors at five sites measuring PM_{10}, $PM_{2.5}$, ozone and SO_2. The County recently stopped ambient monitoring of CO and NO_X. However, the data for those monitors are shown in the table below. The 2009 monitoring network is shown in Figure 11 below.

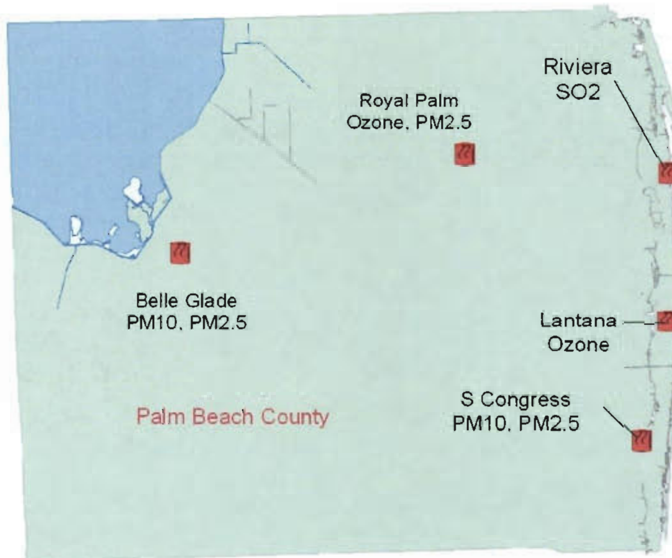

Figure 11. Ambient Monitors in Palm Beach County

On March 12, 2008 the U.S. Environmental Protection Agency announced that it will reduce the 8-hour ozone standard listed above from 85 parts per billion (ppb) to 75 ppb. Upon final redesignation and classification, most likely in 2010, the areas shown in red in Figure 12 will likely no longer be in attainment with the applicable ozone AAQS.

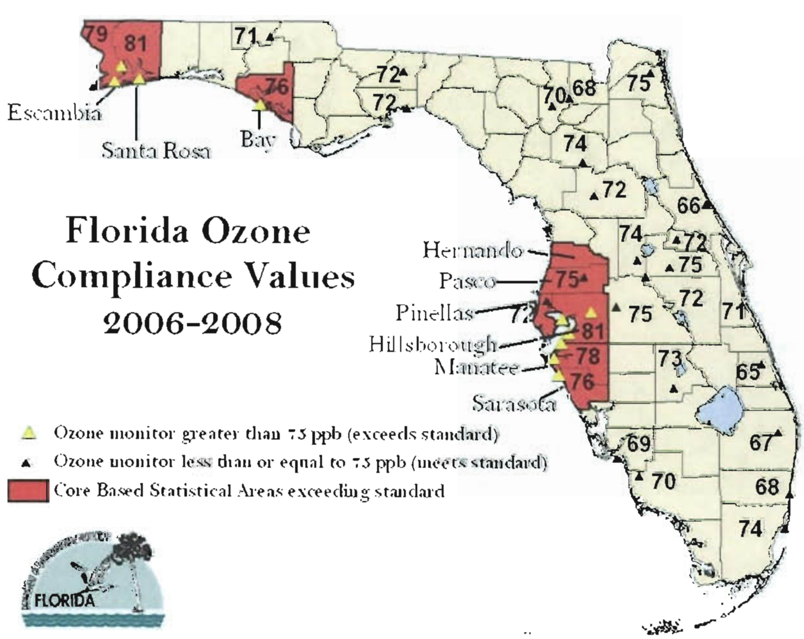

Figure 12. Ozone Compliance Values and Areas that Exceeded the Standard

The 2007 (quality-assured) ambient air quality summaries for the stations nearest to the project site are presented in Table 17. Based on the data including the preliminary 2008 measurements, Palm Beach County will remain in attainment with the new ozone standard.

Table 17. Ambient Air Quality Nearest to Project Site (2007)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	S. Congress	24-hour	67	43		150[a]	ug/m^3
		Annual			23*	50[b]	ug/m^3
$PM_{2.5}$	Royal Palm	24-hour	42	27		35[c]	ug/m^3
		Annual			7	15[d]	ug/m^3
		24-hour	98th percentile		20.9	35[c]	ug/m^3
SO_2	Riviera	3-hour	4	4		500[e]	ppb
		24-hour	2	1		100[e]	ppb
		Annual			1	20[b]	ppb
NO_2	Palm Beach	Annual			8	53[b]	ppb
CO	Palm Beach	1-hour	3	2		35[e]	ppm
		8-hour	1	1		9[e]	ppm
Ozone	Lantana	1-hour	98	92		120[a]	ppb
		8-hour	72	70		75[f,g]	ppb
		8-hour	2007 3-yr attainment		65[f]	75[g]	ppb
		8-hour	2008 3-yr average		67[f]	75[g]	ppb

a. Not to be exceeded on more than an average of one day per year over a three-year period
b. Arithmetic mean
c. Three year average of the 98th percentile of 24-hour concentrations
d. Three year average of the weighted annual mean
e. Not to be exceeded more than once per year
f. Three year average of the 4th highest daily max
g. New EPA standard for ozone

* Insufficient data to produce a valid average (85% complete in 2007).

6.5 Air Quality Impact Analysis

The applicant provided an air quality analysis which included air quality modeling to show compliance with the NAAQS.

Receptor Grid: A combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 5 kilometers from the facility.

Elevated receptors were also used to predict impacts at the condominium complex, Palm Beach House. Receptors were placed at elevations of 50, 60, 70, 80 and 90 meters.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: 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 National Weather Service at Palm Beach International (KPBI) and Miami International Airports respectively. The 5-year period of meteorological data was from 2001 through 2005. The surface weather station was selected for use in this study because the modeling results were similar when comparing surface parameters at KPBI and the project site. The Miami station was selected for use in the study because it is the most representative with regards to this region.

AAQS Analysis

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 results of the AAQS analysis are summarized in Table 18. As shown in the table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

6.6 Additional Impacts Analysis

Ozone

Ozone is an area-wide pollution issue and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

The continuing FPL system-wide NO_X decreases in general (Figure 10), including those due to the RBEC project in particular should help to reduce ozone on a regional basis including Palm Beach County (given cooperation of meteorological factors). The ozone benefits of such reductions will be reinforced by reductions due to implementation of other NO_X control projects, particularly at coal-fueled power plants around the state as many install controls under the Clean Air Interstate Rule (CAIR).

Table 18. Ambient Air Quality Impacts Post-Conversion

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2005- 2008 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	4	60	64	NO	150
	Annual	1	26	27	NO	50
SO_2	24-hour	3	11	14	NO	260
	Annual	1	4	5	NO	60
	3-hour	5	11	16	NO	1,300
NO_2	Annual	17	18	35	NO	100
CO	1-hour	141	3,890	4,031	NO	40,000
	8-hour	71	2,517	2,588	NO	10,000

Impact on Soils, Vegetation, and Wildlife:

Substantial net emissions reductions of approximately 16,000 TPY (5 year average, 2003 through 2007) of pollutants from the Riviera Beach project for sulfuric acid mist, SO_2, PM_{10} and NO_X will help ameliorate past air pollution effects on soils, vegetation and wildlife. The applicant modeled the impacts from the existing facility for comparison purposes.

Impact on Visibility:

There will be significant visibility improvements in the immediate vicinity because of the reduction of particulate emissions due to the RBEC project and the very significant reductions in condensable and fine particulate precursors. The existing units are subject to opacity limitations of 40 percent under present normal operation whereas the replacement units will be subject to a 10% opacity standard.

7. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed RBEC Project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, the draft emissions standards determinations, review of the air quality impact analysis, and the conditions specified in the draft permit.

Teresa Heron is the project engineer responsible for preparing the draft permit conditions. She may be contacted at teresa.heron@dep.state.fl.us and 850-921-9529. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537.

PERMITTEE:

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

DEP File No. 0990042-006-AC
FPL Riviera Beach Energy Center
Plant Conversion Project
Palm Beach County
SIC No. 4911
Expires: December 31, 2015

PROJECT AND LOCATION

This permit authorizes the construction of one nominal 1,250 megawatts (MW) combined cycle unit and ancillary equipment at the FPL Riviera Beach Energy Center previously known as the Riviera Plant.

Two existing steam generators with a total nominal capacity of 600 MW will be shut down and dismantled as part of this project.

The proposed project will be located at 200-300 Broadway, Riviera Beach in Palm Beach County. The UTM coordinates are Zone 17, 594.249 km East and 2960.632 km North.

STATEMENT OF BASIS

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), 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 install the proposed equipment 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.

CONTENTS

Joseph Kahn, Director (Date)
Division of Air Resource Management

FACILITY DESCRIPTION

FPL operates the Riviera Plant (RP), which is an existing power plant (SIC No. 4911). The plant currently consists of two steam generating units designated as Units 1 and 2 that produce 300 MW each of electrical power. Units 1 and 2 use residual fuel oil and natural gas. There are two 298-foot stacks, two fuel oil storage tanks, water intake structures for once-through cooling and other ancillary equipment.

The project is a plant conversion that includes the construction of a nominal 1,250 MW natural gas-fueled combined cycle unit (Unit 5) and requires the permanent shutdown and dismantling of Units 1 and 2. The converted plant will be called the Riviera Beach Energy Center (RBEC). Unit 5 will consist of:

- Three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems;
- Three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors;
- Three maximum 460 million Btu per hour, lower heating value (mmBtu/hr, LHV), natural gas-fueled duct burners (DB) located in the three HRSG (one DB/HRSG);
- Three 149-feet exhaust stacks;
- One nominal 6.3 million distillate fuel oil storage tank; and
- One common nominal 500 MW steam-electrical generator (STG).

Unit 5 will use ultralow sulfur distillate (ULSD) fuel oil as backup fuel.

Additional ancillary equipment to be installed includes: a permanent auxiliary boiler; a temporary boiler used during the construction phase; two emergency generators; two process (fuel) heaters; a diesel fire pump; and a gas compression station. The details of the equipment to be installed are listed in the table below.

The project includes and requires the permanent shutdown and dismantling of Units 1 and 2 and the respective stacks as well as one of the fuel oil storage tanks. When emissions from Unit 5 are considered and offset by reductions from the shut down and dismantlement of Units 1 and 2, there will not be a significant net emission increase in any PSD pollutant.

{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
007	Unit 5A – one nominal 265 MW CTG with supplementary-fired HRSG
008	Unit 5B – one nominal 265 MW CTG with supplementary-fired HRSG
009	Unit 5C – one nominal 265 MW CTG with supplementary-fired HRSG
010	One nominal 85,000 pounds per hour (lb/hr) auxiliary boiler (99.8 mmBtu/hr)
011	Two nominal 10 mmBtu/hr natural gas-fired process heaters (one is a spare)
012	Seven nominal 1,340 horsepower (hp) natural gas compressors
013	Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators
014	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank
015	One temporary 110 mmBtu/hr natural gas-fueled boiler to be used only during construction
016	One nominal 6.3 million distillate fuel oil storage tank

REGULATORY CLASSIFICATION

The RP is a "Major Stationary Source" as defined in Rule 62-210.200, Florida Administrative Code (F.A.C.). The RBEC project does not trigger the rules for the Prevention of Significant Deterioration (PSD) pursuant to Rule 62-212.400, F.A.C. and does not require a best available control technology (BACT) determination.

The RBEC will be a Title V or "Major Source" of air pollution in accordance with Chapter 213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

The RBEC will be subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). Unit 5 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also applies to duct burners (DB) that are incorporated into combined cycle projects.

Two emergency generators will be subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines.

Natural gas compressors will be subject to 40 CFR 60, Subpart JJJJ – NSPS for Stationary Spark Ignition Internal Combustion Engines.

The temporary natural gas-fueled boiler will be subject to 40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units.

The auxiliary boiler and two process (fuel) heaters will be subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial-Commercial-Institutional Steam Generating Units.

The RBEC will be a minor (area source) of hazardous air pollutants (HAP). The RBEC will include emission units that will be subject to certain area source provisions of 40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants (NESHAP). The specific subpart is 40 CFR 63, Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE).

The RBEC will operate units subject to the Title IV Acid Rain provisions of the Clean Air Act (CAA).

The RBEC is subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The project is subject to certification under the Florida Power Plant Siting Act, 403.501-518, Florida Statutes (F.S.) and Chapter 62-17, F.A.C.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Identification of General Provisions Subpart A from NSPS 40 CFR 60 and Subpart A from NESHAP 40 CFR 63.

Appendix GC: General Conditions.

Appendix Db: NSPS Subpart Db Requirements for Industrial-Commercial-Institutional Steam Generating Units.

Appendix Dc: NSPS Subpart Dc Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

Appendix IIII: NSPS Requirements for Compression Ignition Internal Combustion Engines.

Appendix JJJJ: NSPS Requirements for Stationary Spark Ignition Internal Combustion Engines.

Appendix KKKK: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart KKKK.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on February 13, 2009;
- Department request for additional information (RAI) dated March 13, 2009;
- Electronic mail dated April 13, 2009 summarizing resolution of key RAI issue; and
- Draft permit package issued on April 17, 2009.

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Permitting Authority, which is the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP or the Department) at 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority. Telephone: (850)488-0114. Fax: (850)921-9533.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Southeast District Office. The mailing address and phone number of the Southeast District Office are Department of Environmental Protection, Southeast District Office, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401. Telephone: (561)681-6632. Fax: (561)681-6790.

3. Appendices: The following Appendices are attached as part of this permit: Appendices A, Db, Dc, GC (General Conditions), IIII, JJJJ, KKKK, SC, XS and ZZZZ.

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, 62-214, 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: No emissions unit shall be constructed or 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. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. For good cause, the permittee may request that this air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]

8. Permanent Shutdown and Dismantlement of Units 1 and 2: Units 1 and 2 shall be permanently shut down and dismantled before December 31, 2012.
[Application and Avoidance of Rule 62-212.400(4) through (12), F.A.C.]

9. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]

10. Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency (EPA) in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]

11. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and 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 Bureau of Air Regulation with copies to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. UNIT 5 – COMBUSTION TURBINE GENERATORS (EU 007, 008, and 009)

This section of the permit addresses the following emissions units.

Unit 5 and associated equipment
Description: Unit 5 will be comprised of emissions units (EU) 007, 008, and 009. Each EU will consist of: a CTG with automated control, inlet air filtration system and evaporative cooling, a gas-fired HRSG with DB, a HRSG stack, and associated support equipment. The project also includes one STG that will serve the combined cycle unit. **Fuels**: Each CTG fires natural gas as the primary fuel and ULSD fuel oil as a restricted alternate fuel. **Generating Capacity**: Each of the three CTG has a nominal generating capacity of 265 MW. The STG has a nominal generating capacity of 500 MW. The total nominal generating capacity of the "3 on 1" combined cycle unit is approximately 1,250 MW. **Controls**: The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry Low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_X emissions. A SCR system further reduces NO_X emissions. **Stack Parameters**: Each HRSG has a stack at least 149 feet tall with a nominal diameter of 22 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. **Continuous Monitors**: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. NSPS Requirements: The CTG shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the emissions standards in Condition 10 below also assures compliance with the New Source Performance Standards given in 40 CFR 60, Subpart KKKK. Some separate reporting and monitoring may be required by the individual subparts.
   a. *Subpart A, General Provisions*, including:
      - 40 CFR 60.7, Notification and Record Keeping
      - 40 CFR 60.8, Performance Tests
      - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
      - 40 CFR 60.12, Circumvention
      - 40 CFR 60.13, Monitoring Requirements
      - 40 CFR 60.19, General Notification and Reporting Requirements
   b. *Subpart KKKK, Standards of Performance for Stationary Gas Turbines*: These provisions include standards for CTG and DB.

EQUIPMENT AND CONTROL TECHNOLOGY

2. Combustion Turbines-Electrical Generators (CTG): The permittee is authorized to install, tune, operate, and maintain three "G" or "H" technology CTG each with a nominal generating capacity of 265 MW. Each CTG shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The CTG will utilize DLN combustors. [Application and Design]

3. Heat Recovery Steam Generators (HRSG): The permittee is authorized to install, operate, and maintain three new HRSG with separate exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the three CTG (5A to 5C) and deliver steam to the steam turbine-electrical generator (STG). Each HRSG may be equipped with a gas-fired duct burner (DB) having a maximum heat input rate of 460 mmBtu per hour (LHV).

4. CTG/Supplementary-fired HRSG Emission Controls

   a. *Dry Low NO_X (DLN) Combustion*: The permittee shall operate and maintain the DLN system to control NO_X emissions from each CTG when firing natural gas. Prior to the initial emissions performance tests required for each CTG, the DLN combustors and automated control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Wet Injection (WI)*: The permittee shall install, operate, and maintain a WI system (water or steam) to reduce NO_X emissions from each CTG when firing ULSD fuel oil. Prior to the initial emissions performance tests required for each CTG, the WI system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each CTG when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   d. *Oxidation Catalyst*: The permittee shall design and build the project to facilitate possible future installation of an oxidation catalyst system to control CO emissions from each CTG/supplementary-fired HRSG.

   e. *Ammonia Storage:* In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Application and Design; Rule 62-4.070, F.A.C.]

PERFORMANCE RESTRICTIONS

5. Permitted Capacity – Combustion Turbine-Electric Generators (CTG): The maximum heat input rate to each CTG is 2,586 mmBtu per hour when firing natural gas and 2,440 mmBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, LHV of each fuel, and 100% load). Heat input rates will vary depending upon CTG characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

6. Permitted Capacity - HRSG Duct Burners (DB): The total maximum heat input rate to the DB for each HRSG is 460 mmBtu per hour based on the LHV of natural gas. Only natural gas shall be fired in the DB. [Rule 62-210.200(PTE), F.A.C.]

7. Authorized Fuels: The CTG shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. Fuel oil may be fired up to the fuel equivalent of 2,550 hours aggregated over the three CTG during any calendar year. [Rules 62-210.200(PTE), F.A.C.]

8. Hours of Operation: Subject to the operational restrictions of this permit, the CTG may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below. [Rules 62-210.200(Definitions - PTE), F.A.C.]

9. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTG may operate under the following methods of operation.

   a. *Combined Cycle Operation*: Each CTG/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a three-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   b. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.

   c. *Duct Burner (DB) Firing*: When firing natural gas in a CTG, the respective HRSG may fire natural gas in the DB to raise additional steam for use in the STG or in the operation of CTG components. The total combined heat input rate to the DB (all three HRSG) shall not exceed 3,697,920 mmBtu (LHV) during any consecutive 12 months.

   [Application; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

10. Emissions Standards: Emissions from each CTG/DB shall not exceed the following standards developed under state implementation plan (SIP) permitting procedures. Compliance with these limits also assures compliance with the emission limitations in 40 CFR 60, Subpart KKKK.

Pollutant	Fuel	Method of Operation	Initial Stacks Tests		CEMS Rolling Average Limit
			ppmvd [a]	lb/hr [b]	ppmvd [a]
CO [d]	Oil	CTG	10.0	61.0	10.0, 30 unit operating days [c,d]
	Gas	CTG & DB	7.6	52.7	7.5, 30 unit operating days [c,d]
		CTG Normal Mode	5.0	29.0	
NO_X [e]	Oil	CTG	8.0	80.0	8.0, 30 unit operating days [c,e]
	Gas	CTG & DB	2.0	22.8	2.0, 30 unit operating days [c,e]
		CTG Normal Mode	2.0	19.3	
VOC [f]	Oil	CTG	6.0	18.9	NA
	Gas	CTG & DB	1.9	7.2	
		CTG Normal Mode	1.5	4.8	
NH_3 [g]	Oil/Gas	CTG, All Modes	5	NA	NA
SAM/SO_2 [h]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
PM/PM_{10} [i]			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		

a. Concentration standards are given in terms of parts per million, by volume, dry at 15 percent oxygen and abbreviated as ppmvd.
b. The mass emission rate standards in pounds per hour (lb/hr) are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations filed with the Department.
c. "Unit operating day" means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period. [40 CFR 60.4420]
d. Compliance with the continuous 30-unit operating days rolling CO standard shall be demonstrated based on data collected by the required CEMS. The initial EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate initial performance guarantees for natural gas, oil, and DB mode.
e. Continuous compliance with the 30-unit operating days rolling NO_X standards shall be demonstrated based on data collected by the required CEMS and will also insure compliance with the less stringent Subpart KKKK limits of 15 and 42 ppmvd for gas and fuel oil respectively on a 30-unit operating day rolling average basis. The initial 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 natural gas, fuel oil, 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).
f. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required.
g. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.
h. The clean fuel sulfur specifications and visible emissions standard effectively limit the potential emissions of SAM and SO_2 from the CTG. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
i. The clean fuel sulfur specifications, low CO and NO_X limits, and the visible emissions standard will effectively limit $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

[Application and Avoidance of Rule 62-212.400(4) through (12), F.A.C.; 40 CFR 60, Subpart KKKK]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 10 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

11. Operating Procedures: The emission standards established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the CTG, DB, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3), F.A.C.]

12. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Applicant Request and Rule 62-4.070(3), F.A.C.]

13. 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. [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]

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. [Rule 62-210.200(159), F.A.C.]

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

15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switching and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, NO_X and CO emission data exclusions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *STG/HRSG System Cold Startup: For cold startup of the steam turbine system, NO_X and CO emission data exclusions for any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.*

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

    b. *Shutdown Steam Turbine System: For shutdown of steam turbine system, NO_X and CO emission data exclusions for any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.*

    c. *CTG/HRSG System Cold Startup: For cold startup of a CTG/HRSG system, NO_X and CO emission data exclusions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.*

    d. *Fuel Switching: For fuel switching, NO_X and CO emission data exclusions shall not exceed two (2) hours in any 24-hour period.*

16. Ammonia Injection: Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG.
[Design; Rules 62-4.070(3) and 62-210.700, F.A.C.]

17. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 7 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

19. Initial Compliance Determinations: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the unit. Each CTG shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Referenced method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

20. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 30-unit operating days rolling average CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subpart KKKK]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. Testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

    {Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

    [Rules 62-4.070(3) and 62-297.310(7)(a)4, F.A.C.]

22. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$: In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition 28, the visible emissions standard and the CO/NO_X continuous monitoring. [Rule 62-4.070(3), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

23. Continuous Emissions Monitoring System(s) (CEMS): The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle 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 prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors:* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A 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. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report in 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 Monitors:* Each 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 Monitors:* 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.

24. 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 for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to International Organization of Standardization (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. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *30-Unit Operating Day Rolling Averages*: 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. For purposes of determining compliance with the 30-unit operating day rolling CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 30-unit operating day rolling average shall be determined using the remaining hourly data in the 30-day rolling period.

{Permitting Note: There may be more than one 30-unit operating day compliance demonstration required for CO and NO_X emissions depending on the use of alternate fuels.}

d. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 17 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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.

[Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3), F.A.C.]

25. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of 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 and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

26. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction and fuel switching). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rule 62-4.070(3), F.A.C.]

27. 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 each CTG for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. 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. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3), F.A.C.]

28. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

a. *Natural Gas:* Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

b. *ULSD Fuel Oil:* Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

29. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

30. Excess Emissions Reporting:

a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the permit emission standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart KKKK, excess emissions from the CTG are defined as: a specified averaging period over which either the NO_X emissions are higher than the applicable emission limit in 40 CFR 60.4320; or the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in 60.4330. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7, and 60.4420]

31. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

B. AUXILIARY BOILER AND TEMPORARY CONSTRUCTION BOILER (010 AND 015)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
010	One nominal 85,000 pounds per hour (lb/hr) natural gas fueled auxiliary boiler (99.8 mmBtu/hr)
015	One temporary 110 mmBtu/hr natural gas-fueled boiler to be used only during construction

AUXILIARY BOILER REQUIREMENTS

1. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99.8 mmBtu/hr (85,000 lb/hr) to produce steam during start up of the CTG. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]
2. Hours of Operation: The hours of operation of the auxiliary boiler shall not exceed 500 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]
3. NSPS Subpart Dc Applicability: The auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Steam Generating Units. Specifically, this emission unit shall comply with 40 CFR 60.48c Reporting and Recordkeeping Requirements. [40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].
4. Auxiliary Boiler Emissions Limits: The auxiliary boiler shall comply with the following emission limits.

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.05 lb/mmBtu	0.08 lb/mmBtu	2 gr S/100 SCF natural gas spec and 10% Opacity

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

{Permitting note: There are no Subpart Dc emission standards for auxiliary boilers fueled by natural gas.}

5. Auxiliary Boiler Testing Requirements: The auxiliary boiler shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. [Rule 62-297.310(7)(a)1, F.A.C.]

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources

6. Notification: Initial notification is required for the auxiliary boiler pursuant to 40 CFR 60.7.
7. Reporting: The permittee shall maintain records of the amount of natural gas used in the auxiliary boiler. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

B. AUXILIARY BOILER AND TEMPORARY CONSTRUCTION BOILER (010 AND 015)

TEMPORARY BOILER REQUIREMENTS

8. Equipment: The permittee is authorized to install, operate, and maintain a temporary boiler during the construction of the RBEC with a maximum design heat input of 110 mmBtu/hr.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

9. Hours of Operation: The hours of operation of the temporary boiler shall not exceed 500 hours per year and the temporary boiler shall not operate beyond the expiration date of this permit.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

10. NSPS Subpart Db Applicability: The temporary 110 mmBtu natural gas-fueled boiler is subject to all applicable requirements of 40 CFR 60, Subpart Db which applies to Industrial, Commercial, or Institutional Steam Generating Units.
    [40 CFR 60, NSPS-Subpart Db - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Db].

C. PROCESS HEATERS (EU 011)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
011	Two nominal 10 mmBtu/hr natural gas-fired process heaters (one is a spare)

1. Equipment: The permittee is authorized to install, operate, and maintain two 10 mmBtu/hr process heaters for the purpose of heating the natural gas supply to the CTG.
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

2. Hours of Operation: The two natural gas-fueled process heaters are allowed to operate a combined total of 8760 hours per year. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

3. NSPS Subpart Dc Applicability: Each process heater is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR 60.48c Reporting and Recordkeeping Requirements.
[40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]

4. Emission Limits: Each natural gas fired process heater shall comply with the following emission limits.

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.095 lb/mmBtu	0.08 lb/mmBtu	2 gr S/100 SCF natural gas spec and 10% Opacity

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

{Permitting note: There are no Subpart Dc emission standards for gas-fired process heaters fueled by natural gas.}

5. Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the emission limits values can be used to fulfill this requirement.
[Rule 62-297.310(7)(a)1, F.A.C.]

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources

6. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of natural gas used in the process heaters and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.48c and 40 CFR 60.7. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A and Dc]

D. COMPRESSOR STATION (EU 012)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	Seven nominal 1,340 horsepower (hp) natural gas compressors

1. Equipment: The permittee is authorized to install, operate, and maintain seven nominal 1,340 horsepower (hp) natural gas compressors. Maximum heat input shall not exceed 10.11 mmBtu/hr each. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
2. Hours of Operation and Fuel Specifications: Each compressor is allowed to operate continuously (8760 hr/yr). The compressors are allowed to burn natural gas only. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
3. NSPS Subpart JJJJ Applicability: These compressors are Stationary Spark Ignition Internal Combustion Engines and shall comply with applicable provisions of 40 CFR 60, Subpart JJJJ. [40 CFR 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines]
4. NESHAPS Subpart ZZZZ Applicability: These compressors are Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart JJJJ. [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]
5. Pollution Control Equipment: Each gas compressor shall be equipped with an oxidation catalyst to control CO and VOC/hydrocarbons. [Applicant request; Rule 62-4.070(3), F.A.C.]
6. Visible Emission (VE) Limit: Each natural gas compressor shall comply with a visible emission limit of 10% opacity. [Applicant request; Rule 62-4.070(3), F.A.C.]
7. Emissions Limits: Each natural gas compressors shall comply with the following emission limits.

Standard (manufacture date)	CO (g/hp-hr)[a]	VOC (g/hp-hr)	NO_X (g/hp-hr)	PM (g/hp-hr)	SO_2 (gas S spec.)
Permit Emission Limit	0.10	0.16	1.5[b]	0.034	2 gr/100 SCF
Subpart JJJJ (1/1/2008)	4.0	1.0	2.0	NA	
Subpart JJJJ (7/1/2010)	2.0	0.7	1.0		

   a. grams per horsepower-hour (g/hp-hr)

   b. Reduced to 1.0 g/hp-hr if manufacture date is 7/1/2010 or later to insure compliance with Subpart JJJJ.

   {Permitting note: Installation of an oxidation catalyst and adherence to the visible emission standard and fuel specification shall be considered sufficient to insure compliance with the listed PM limit.}

   [Applicant request; 40 CFR 60, Subpart JJJJ; Rule 62-4.070(3), F.A.C.]

8. Compressor Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, VOC, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. With the exception of visible emissions testing, manufacturer certification can be provided to the Department in lieu of actual testing. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4244]

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
18	Determination of Volatile Organic Compounds Emissions from Stationary Sources

[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subpart JJJJ and 40 CFR 60.8]

10. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of natural gas used in the compressor station and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.4245 and 40 CFR 60.7. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A and JJJJ]

E. EMERGENCY GENERATORS (013)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
013	Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators

1. Equipment: The permittee is authorized to install, operate, and maintain two 2,250 kW emergency generators. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
2. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per generator. The generators shall burn ultralow sulfur diesel fuel oil (0.0015% sulfur). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
3. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]
4. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]
5. Emissions Limits: Each emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. Manufacturer certification can be provided to the Department in lieu of actual testing.

Source (model year)	CO (g/hp-hr)	PM (g/hp-hr)	Hydrocarbons (g/hp-hr)	NO_X (g/hp-hr)
Subpart IIII (2007-2010)	8.5	0.4	1.0	6.9
Subpart IIII (2011 and later)	2.6	0.15	4.8 (NMHC[a]+NO_X)	

a. NMHC means Non-Methane Hydrocarbons.

[Applicant Request; 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

6. Visible Emission (VE) Limit: Each liquid-fueled emergency generator shall comply with a visible emission limit of 10% opacity. An initial VE test shall be conducted in accordance with EPA Method 9 within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup. [Applicant request; Rule 62-4.070(3), F.A.C.]
7. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of fuel used in the emergency generators and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.4214 and 40 CFR 60.7. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A and IIII]

F. EMERGENCY FIRE PUMP (014)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
014	One emergency diesel fire pump engine (≤ 300 hp) and a nominal 500 gallon fuel oil storage tank

1. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (≤ 300 hp) and an associated nominal 500 gallon fuel oil storage tank. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
2. Hours of Operation: The fire pump may operate in response to emergency conditions and 80 non-emergency hours per year for maintenance testing. [Applicant Request; Rule 62-210.200 (PTE), F.A.C.]
3. Authorized Fuel: This unit shall fire ULSD fuel oil, which shall contain no more than 0.0015% sulfur by weight. [Applicant Request]
4. NSPS Subpart IIII Applicability: The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]
5. Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII.

Model Year	CO (g/hp-hr)	NMHC + NO_X (g/hp-hr)	PM (g/hp-hr)
Subpart IIII (2008)	2.6	7.8	0.40
Subpart IIII (2009 or later)	NA	3.0	0.15

[Applicant Request; 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

6. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

G. DISTILLATE FUEL OIL STORAGE TANK (016)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
016	One nominal 6.3 million gallon distillate fuel oil storage tank

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb.
[40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one nominal 6.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur diesel fuel oil to the gas turbines.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year).
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective MSDS for the ULSD fuel oil stored in the tank. [Rule 62-4.070(3), F.A.C.; Avoidance of 40 CFR 60, Subpart Kb]

   {Permitting Note: An evaluation of several Material Safety Data Sheets (MSDS) by the Department and applicant demonstrated that the vapor pressure is much less than 3.5 kPa for ULSD fuel oil.}

CONTENTS

NSPS SUBPART A AND NESHAP SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

NSPS - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NSPS FOR INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

The temporary 110 mmBtu/hr boiler is regulated as ARMS Emissions Unit (EU) No. 015. This EU is subject to the applicable requirements of 40 CFR 60, Subpart Db-- Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart Db

The auxiliary boiler rated at 99.8 mmBtu/hr is regulated for the purposes of ARMS as EU 010. Two natural gas process heaters are regulated as one unit for purposes of the ARMS or EU No. 011. These two EU are subject to all applicable provisions of 40 CFR 60, Subpart Dc-- Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart Dc

The key reporting and recordkeeping requirements are listed below.

§ 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.

(2) Not applicable.

(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.

(b)-(f) Not applicable.

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

(h) Not applicable.

(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 (Not applicable);
    b. Determination of Prevention of Significant Deterioration (Not applicable);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
    d. 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 Requirements for Stationary Compression Ignition Internal Combustion Engines

The two nominal 2,250 kilowatts emergency generators are regulated as one unit for purposes of the ARMS or EU No. 013. The nominal 300 horsepower (hp) fire engine pump is regulated as ARMS EU No. 014. These two EU are subject to the applicable requirements of 40 CFR 60, Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart IIII

NSPS REQUIREMENTS FOR NSPS FOR STATIONARY SPARK IGNITION INTERNAL COMBUSTION ENGINES

The seven nominal 1,340 horsepower (hp) natural gas compressors are regulated as one unit for purposes of the ARMS or EU No. 012. They are subject to the applicable requirements of 40 CFR 60, Subpart JJJJ--Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart JJJJ

NSPS SUBPART KKKK REQUIREMENTS FOR GAS TURBINES AND DUCT BURNERS

Combined Cycle Unit 5 is regulated as ARMS EU 007, 008 and 009. These EU are subject to the applicable requirements of 40 CFR 60, Subpart KKKK--Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart KKKK

Table 1 of Subpart KKKK is a listing of the key NO_X limits from Subpart KKKK that apply to the RBEC Unit 5 project. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

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

Combustion turbine type	Combustion turbine heat input at peak load (higher heating value)	NO_X emission standard
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).

* Only the portion of the table that includes the NO_X Requirements applicable to the RBEC Unit 5 project.

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this 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 two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [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 permitee shall notify the Department or the appropriate Local Program 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 or organic solvents 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) and62-210.200(203), 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 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. 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. [Rule 62-297.310(2), F.A.C.]

12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. 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.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: 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. [Rule 62-297.310(7)(a)9, F.A.C.]

17. 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)(b), F.A.C.]

18. 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, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.
2) The facility at which the emissions unit is located.
3) The owner or operator of the emissions unit.
4) 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.
5) 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.
6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8) The date, starting time and duration of each sampling run.
9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10) The number of points sampled and configuration and location of the sampling plane.
11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12) The type, manufacturer and configuration of the sampling equipment used.
13) Data related to the required calibration of the test equipment.
14) Data on the identification, processing and weights of all filters used.
15) Data on the types and amounts of any chemical solutions used.
16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18) All measured and calculated data required to be determined by each applicable test procedure for each run.
19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
20) 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.
21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. 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.]

RECORDS AND REPORTS

19. 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 five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(2), F.A.C.]

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ______________________________________

Address: ____

Monitor Manufacturer: _____________________________________

Model No.: ____

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: _________________________________

Total source operating time in reporting period [1]: ______________________

Emission data summary [1]	CMS performance summary [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ %[2]

1 For opacity, record all times in minutes. For gases, record all times in hours.

2 For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: ____

Signature: ____________________________________ *Date*: ______________

Title: ______________________________________

NESHAPS REQUIREMENTS-STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

The seven nominal 1,340 horsepower (hp) natural gas compressors are regulated as one Unit for purposes of the ARMS or Emissions Unit No. 012. The two nominal 2,250 kilowatts emergency generators are regulated as one Unit for purposes of the ARMS or Emissions Unit No. 013. These reciprocating internal combustion engines (RICE) are subject to the notification requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

Link to Subpart ZZZZ

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Friday, April 17, 2009 2:18 PM
To: 'randall_labauve@fpl.com'
Cc: 'agreene@co.palm-beach.fl.us'; 'cclerk@rivierabch.com'; 'jmcdonald@townofpalmbeach.com'; 'lfrankel@wpb.org'; 'salbury@townofmangoniapark.com'; 'tmills@pbstownhall.org'; 'townclerk@lakeparkflorida.gov'; 'abrams.heather@epa.gov'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; Long, Jack; 'anderson.lennon@dep.state.fl.us'; Halpin, Mike; 'james_stormer@doh.state.fl.us'; 'barbara_p_linkiewicz@fpl.com'; 'sosbourn@golder.com'; Gibson, Victoria; Sturtevant, Toni; Moore, Ronni; Mulkey, Cindy; 'Laxmana_Tallam@doh.state.fl.us'; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: FPL - RIVIERA POWER PLANT; 0990042-006-AC
Attachments: INTENT006.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/0990042.006.AC.D_pdf.zip

Owner/Company Name: FLORIDA POWER and LIGHT (PRV)
Facility Name: F P and L / RIVIERA POWER PLANT
Project Number: 0990042-006-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION/ Conversion Project
Facility County: PALM BEACH
Processor: Al Linero

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

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

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)

Livingston, Sylvia

From: Addie Greene [AGreene@pbcgov.org]
Sent: Monday, April 20, 2009 12:41 PM
To: Livingston, Sylvia
Subject: RE: FPL - RIVIERA POWER PLANT; 0990042-006-AC

Ms. Livingston, thanks for the info. On the Riviera Beach FPL Plant.
Commissioner Addie Greene

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Friday, April 17, 2009 2:18 PM
To: randall_labauve@fpl.com
Cc: Addie Greene; cclerk@rivierabch.com; jmcdonald@townofpalmbeach.com; lfrankel@wpb.org; salbury@townofmangoniapark.com; tmills@pbstownhall.org; townclerk@lakeparkflorida.gov; abrams.heather@epa.gov; forney.kathleen@epa.gov; dee_morse@nps.gov; Long, Jack; anderson.lennon@dep.state.fl.us; Halpin, Mike; james_stormer@doh.state.fl.us; barbara_p_linkiewicz@fpl.com; sosbourn@golder.com; Gibson, Victoria; Sturtevant, Toni; Moore, Ronni; Mulkey, Cindy; Laxmana_Tallam@doh.state.fl.us; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: FPL - RIVIERA POWER PLANT; 0990042-006-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/0990042.006.AC.D_pdf.zip

Owner/Company Name: FLORIDA POWER and LIGHT (PRV)
Facility Name: F P and L / RIVIERA POWER PLANT
Project Number: 0990042-006-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION/ Conversion Project
Facility County: PALM BEACH
Processor: Al Linero

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

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

Livingston, Sylvia

From: Randall_R_LaBauve@fpl.com
Sent: Wednesday, April 29, 2009 4:22 PM
To: Livingston, Sylvia
Subject: Re: FW: FPL - RIVIERA POWER PLANT; 0990042-006-AC
Attachments: pic19975.gif; INTENT006.pdf

Received and opened. Thank you.

Randy
"Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us>

"Livingston, Sylvia"
<Sylvia.Livingston@dep.state.fl.us>
04/29/2009 04:19 PM

To: "randall_labauve@fpl.com" <'randall_labauve@fpl.com'>
cc:
Subject: FW: FPL - RIVIERA POWER PLANT; 0990042-006-AC

Dear Mr. LaBauve,
We have not received confirmation that you were able to access the documents attached to this April 17th e-mail, as well as the documents provided in the link (http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0990042.006.AC.D_pdf.zip) referenced in the email. Please confirm receipt by opening the attachment and clicking on the link to the permit documents, and sending a reply to me.

The Division of Air Resource Management is sending electronic versions of these documents rather than sending them Return Receipt Requested via the US Postal service. Your "receipt confirmation" reply serves the same purpose as tracking the receipt of the signed "Return Receipt" card from the US Postal Service. Please let me know if you have any questions.

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

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