Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Bureau of Air Regulation

FROM: Al Linero, Special Projects Section *alj*

DATE: April 21, 2008

SUBJECT: Draft Air Permit No. PSD-FL-396
Project No. 0990646-002-AC
Florida Power and Light (FP&L) West Coast Energy Center
Combined Cycle Unit 3

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

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

This draft permit is to construct an additional 1,250MW natural gas-fueled combined cycle unit (Unit 3) and ancillary equipment at the FP&L West Coast Energy Center located at 20505 State Road 80, Loxahatchee, Palm Beach County, Florida.

I recommend your approval of the attached Draft Permit.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light Company (FP&L)
700 Universe Boulevard
Juno Beach, Florida 33408

FP&L West County Power Center
Combined Cycle Unit 3
DEP File No. 0990646-002-AC
Permit No. PSD-FL-396

PROJECT DESCRIPTION

Unit 3 will consist of: three nominal 250 megawatts (MW) combustion turbine-electrical generators (CTG); three supplementary-fired heat recovery steam generators (HRSG); a single nominal 500 MW steam turbine-electrical generator (STG); a 26-cell mechanical draft cooling tower; and three exhaust stacks. Additional equipment includes two 2,250 kilowatts emergency generators, two natural gas-fueled process heaters and other associated support equipment.

Unit 3 will be permitted to operate continuously while firing inherently clean natural gas. Ultralow sulfur diesel fuel oil ULSD FO (0.0015 percent sulfur) will be allowed as backup fuel for 500 hours per year per CTG. Gas-fired duct burners (DB) located within the HRSG will be used for limited periods of time to raise additional steam for use in the STG.

Following is the determination of best available control technology (BACT) based on selective catalytic reduction (SCR) and efficient combustion of inherently clean fuels.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr	ppmvd @ 15% O_2
CO	Oil	CTG	8.0	42.0	8.0, 24-hr
	Gas	CTG & DB	7.6	52.5	6, 12-month [h]
		CTG Normal	4.1	23.2	
NO_X	Oil	CTG	8.0	82.4	8.0, 24-hr
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr <u>and</u> 15, 4-hr
		CTG Normal	2.0	20.0	
PM/PM_{10}	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur FO		
VOC	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
		CTG Normal	1.2	4.1	
NH_3	Oil/Gas	CTG, All Modes	5	NA	NA

Emissions from the emergency generators and process heaters miscellaneous equipment 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 required ambient impact analyses, 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).*

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

7/21/08

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

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 25, 2008

Electronically Sent – Received Receipt Requested

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

Re: DEP File No. 0990646-002-AC (PSD-FL-396)
FP&L West County Energy Center
Combined Cycle Unit 3

Dear Mr. LaBauve:

On December 6, 2007 you submitted an application for an air construction permit pursuant to the rules for the Prevention of Significant Deterioration (PSD) in accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.) to construct an additional combined cycle unit (Unit 3) at the facility identified above. Enclosed are the following documents:

- The Technical Evaluation and Preliminary Determination;
- Draft Air Permit;
- Written Notice of Intent to Issue Air Permit; and
- Public Notice of Intent to Issue Air Permit. This is the actual notice 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 Deborah Nelson at 850-921-9537 or Alvaro Linero at 850-921-9523.

Sincerely,

Trina Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures
TLV/aal

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

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

Authorized Representative:
Mr. Randall R. LaBauve, Vice President

Air Permit No. PSD-FL-396
Air Permit No. 0990646-002-AC
FP&L West County Energy Center
Combined Cycle Unit 3
Palm Beach County

Facility Location: The applicant, Florida Power and Light Company (FP&L), is presently constructing the West County Energy Center (WCEC) in Palm Beach County at 20505 State Road 80, Loxahatchee, Florida.

Project: On December 6, 2007, FP&L submitted an application for an air construction permit pursuant to the rules for the Prevention of Significant Deterioration (also called a PSD Permit) in Rule 62-212.400, Florida Administrative Code (F.A.C.) for an additional 1,250 megawatts (MW) natural gas fueled combined cycle unit (Unit 3) and ancillary equipment at the facility identified above. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters F.A.C. 62-4, 62-210, and 62-212. The proposed project is not exempt from air permitting requirements and an Air Permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The 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 the address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above.

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

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

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 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 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a revised 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 (telephone: 850/245-2241; fax: 850/245-2303). Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

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

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by electronic mail with received receipt requested before the close of business on **April 25, 2008** to the persons listed below.

Randall R. LaBauve: randall_labauve@fpl.com
Jim Little, EPA Region 4: little.james@epa.gov
Katy Forney: forney.kathleen@epa.gov
Dee Morse, U.S. National Park Service: dee_morse@nps.gov
Ken Kosky, PE, Golder: kkosky@golder.com
Lee Hoefert, DEP SED: lee.hoefert@dep.state.fl.us
Mike Halpin, DEP Siting: mike.halpin@dep.state.fl.us
Barbara Linkiewicz, FP&L: barbara_p_linkiewicz@fpl.com
Paul Darst, Department of Community Affairs: paul.darst@dca.state.fl.us
Jim Stormer, Palm Beach County Public Health Unit: james.stormer@doh.state.fl.us
Chair, Palm Beach County BCC: agreene@co.palm-beach.fl.us
Mayor, Village of Royal Palm Beach: dlodwick@royalpalmbeach.com
Mayor, Village of Wellington: twenham@ci.wellington.fl.us
Clerk, Loxahatchee Groves: clerk@loxahatcheegroves.org
Scott Davis, EPA Region 4: davis.scottr@epa.gov
Sandra Silva, U.S. Fish and Wildlife Service: sandra_silva@fws.gov
Nancy J. Gribble: NanJ58@aol.com
Alexandria Larson: daniellarson@earthlink.net
Patricia D. Curry: GremlinLtd@aol.com
Barry Silverman: Barryboca@aol.com
J. William Blouda: blouda@fau.edu
Palm Beach County Environmental Coalition: pbcenvirocoalition@gmail.com

Clerk Stamp

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

Mary L. Harvey (Clerk) 4/25/08 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Project No. 0990646-002-AC / Draft Air Permit No. PSD-FL-396
Florida Power and Light Company
West County Energy Center
Palm Beach County, Florida

Applicant: The applicant for this project is Florida Power and Light Company (FP&L). The applicant's authorized representative and mailing address is: Mr. Randall R. LaBauve, Vice President, Florida Power and Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Facility Location: The applicant, FP&L, is presently constructing the West County Energy Center (WCEC Units 1 and 2) in Palm Beach County at 20505 State Road 80, Loxahatchee, Florida.

Project: On December 6, 2007 FP&L submitted an application for an Air Permit pursuant to the rules for the Prevention of Significant Deterioration (also called a PSD Permit) in Rule 62-212.400, Florida Administrative Code (F.A.C.). An air permit is one of several authorizations needed to construct an additional 1,250 megawatts (MW) natural gas fueled combined cycle unit (Unit 3) and ancillary equipment at the WCEC. A determination of best available control technology (BACT) pursuant to Rule 62-212.400(6), F.A.C. was required for emissions of carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC).

Unit 3 will consist of: three nominal 250 MW combustion turbine-electrical generators (CTG); three supplementary-fired heat recovery steam generators (HRSG); a single nominal 500 MW steam turbine-electrical generator (STG); a 26-cell mechanical draft cooling tower; and three exhaust stacks. Additional equipment includes two 2,250 kilowatts emergency generators, two natural gas-fueled process heaters and other associated support equipment.

Unit 3 will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur diesel (ULSD) fuel oil (0.0015 percent sulfur) will be allowed as backup fuel for 500 hours per year per CTG. Gas-fired duct burners (DB) located within the HRSG will be used for limited periods of time to raise additional steam for use in the STG.

The maximum potential annual emissions in tons per year (TPY) from the Unit 3 project are summarized in the following table. Emissions from the previously approved project for Units 1 and 2 are also included for information purposes.

Pollutant	Units 1 & 2 TPY	Unit 3 TPY	PSD Significant Emission Rate, TPY	PSD Review Required?	WCEC Total TPY
CO	1,038	521	100	Yes	1,559
Pb (lead)	0.055	0.022	0.6	No	0.067
NO_X	713	359	40	Yes	1,072
PM/PM_{10}	501/277	250/139	25/15	Yes	751/416
SO_2	399	199	40	Yes	598
SAM	81	40	7	Yes	121
VOC	165	82	40	Yes	247

Selective catalytic reduction (SCR) systems with ammonia injection will be used in conjunction with Dry Low-NO_X combustion (gas firing) and wet injection (oil firing) to control NO_X emissions. The Department's proposed BACT NO_X emission limit is 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2) while firing natural gas. Sufficient catalyst will be used to minimize emissions of ammonia reagent. The Department's proposed BACT NO_X limit while firing ULSD fuel oil is 8.0 ppmvd @15% O_2. The Department's proposed BACT CO emission limit is 8.0 ppmvd @15% O_2 on a 24-hour basis while burning gas, ULSD fuel oil, or using the DB. A BACT CO limit of 6 ppmvd @15% O_2 applies on a 12-month rolling average. A BACT CO limit of 4.1 ppmvd @15% O_2 applies during initial and annual full load tests and while burning natural gas without use of the DB.

Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emissions of CO and NO_X will be continuously monitored to demonstrate compliance with the conditions of the permit. BACT determinations for the ancillary equipment including the cooling tower, emergency generators and process heaters are detailed in the Technical Evaluation and Preliminary Determination available at the locations and website addresses indicated below.

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed Unit 3 project and the approved Unit 1/2 project are greater than the modeling significant impact levels applicable to areas in the vicinity of the project (i.e. PSD Class II Areas) for all pollutants except for the CO and 3-hour SO_2 impacts. Therefore, multi-source PSD increment consumption modeling was required for SO_2 for the 24-hour and annual averaging times, PM_{10} for the 24 hour and annual averaging times and for NO_2. The maximum predicted project impacts in the Class I Everglades National Park (ENP) are less than the applicable modeling significant impact levels for all pollutants. Therefore, multi-source increment consumption modeling was not required. The results of the Class II multi-source increment consumption modeling are shown in the table below.

	Class II PSD Increment Consumed ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed (%)
SO_2 24-hour	29	91	32
SO_2 Annual	5	20	25
PM_{10} 24-hour	24	30	80
PM_{10} Annual	4	17	24
NO_2 Annual	8	25	32

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and F.A.C. Chapters 62-4, 62-210, and 62-212. The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The 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 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 the address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. In addition electronic copies of these documents are available on the following website: www.dep.state.fl.us/air/eproducts/apds/default.asp .

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

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 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 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000 (telephone: 850/245-2241; fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within 14 days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

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

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

Mediation: Mediation is not available for this proceeding.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company (FP&L)
West County Energy Center Unit 3

One Nominal 1,250-Megawatt Combined Cycle Unit

Palm Beach County

DEP File No. 0990646-002-AC (PSD-FL-396)

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

April 25, 2008

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company (FP&L)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

Processing Schedule

- December 6, 2007: Received Prevention of Significant Deterioration (PSD) application
- December 21, 2007: Received supplemental information from FP&L
- January 21, 2008: Issued request for additional information (RAI)
- February 13, 2008: Held informational meeting in Royal Palm Beach
- March 14, 2008: Received responses from FP&L to RAI (application complete)
- April 25, 2008: Preliminary determination issued

Facility Description and Location

FP&L is presently constructing the West County Energy Center (WCEC) at 20505 State Road (SR) 80, Loxahatchee, Palm Beach County. The location with respect to other FP&L facilities in Florida is shown in Figure 1. The WCEC site is bounded by SR 80 (also known as Southern Boulevard) on the south, FP&L electrical transmission lines on the west, a major electrical substation on the northwest corner, as well as mining lands immediately north and east.

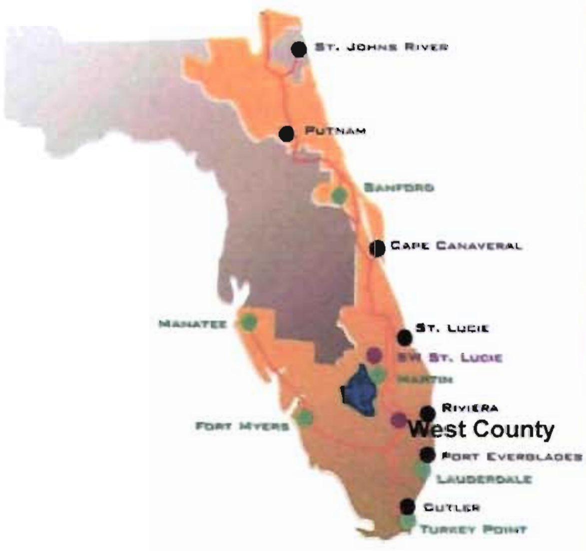


Figure 1. Location of FP&L WCEC

Figure 2. Aerial View, Rendition from Northeast

The Arthur R. Marshall (ARM) Loxahatchee National Wildlife Refuge (NWR) operated by the U.S. Fish and Wildlife Service (USFWS) is located immediately south of Southern Boulevard. The northwest corner of the refuge is visible in the upper left hand side of Figure 2, which is a rendition of the future plant on the proposed site looking from the northeast.

The southernmost corner of the J.W. Corbett Wildlife Management Area, operated by the Florida Fish and Wildlife Management Commission, is located approximately 4 miles north of the site.

With respect to Figure 3 below, the Town of Loxahatchee Groves is located approximately 4 miles east of the site. The Villages of Wellington and Royal Palm Beach are also located several miles generally east of the site. Other areas such as The Acreage, Deer Run and Indian Trails are populated and unincorporated communities east of and near to the site.

The Cities of Belle Glade and Pahokee are adjacent to Lake Okeechobee which is located about 20 miles west to northwest of the WCEC.

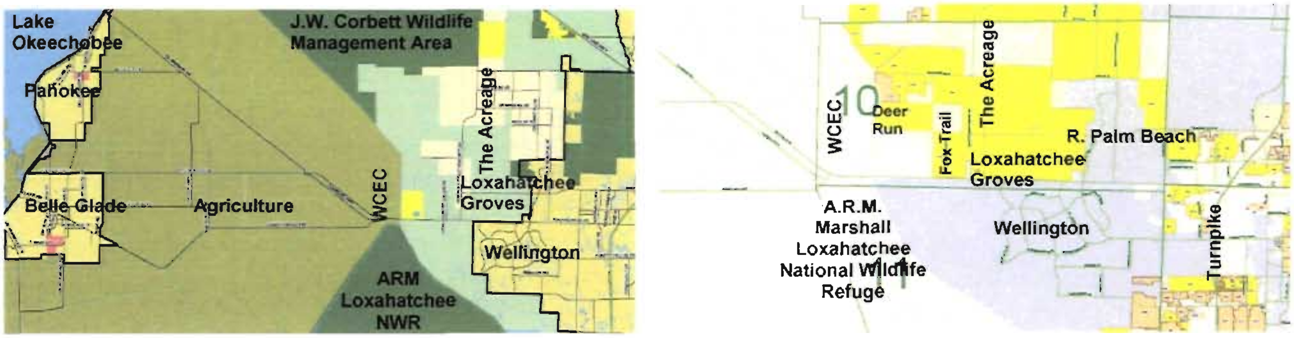


Figure 3. Municipalities, Communities and Wildlife Areas nearest to the FP&L WCEC

The site is located approximately 107 kilometers (km) north of the PSD Class I Everglades National Park. The UTM coordinates of the site are Zone 17; 562.19 km East; 2953.04 km North.

Regulatory Categories

40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). The facility under construction is subject to certain NSPS. Unit 3 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 additional emergency generators are subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines. Two additional process heaters are subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants (NESHAP). The facility under construction is a major source of hazardous air pollutants (HAP). The new unit is potentially subject to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbine electrical-generator (CTG) such as planned for this project.

Title IV, Clean Air Act, Acid Rain Provisions. The facility will operate units subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits. The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY) or because it is a Major Source of HAP. 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).

Prevention of Significant Deterioration (PSD). The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 TPY. Potential emissions of at least one regulated pollutant exceed 100 TPY, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 Florida Administrative Code (F.A.C.). Units 1 and 2 were permitted previously under PSD permit (PSD-FL-354).

Siting. The two units already under construction were originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C. An application is under review to modify the certification to reflect the capacity of the third unit.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a third "three-on-one" combined cycle unit (Unit 3) where two such units (Units 1 and 2) are presently under construction. Combined cycle Unit 3 will consist of: three nominal 250 megawatt (MW) "G" Class combustion turbine-electrical generators (CTG) evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors and a nominal 428 mmBtu/hour (lower heating value – LHV) gas-fired DB; three 149 foot exhaust stacks; one 26-cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.

Additional ancillary equipment will include: two 2250 KW emergency generators and two natural gas fired fuel heaters. 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 requests 500 hours per year per CTG (or equivalent) for oil firing. The ULSD FO will be stored in the tanks under construction for Units 1 and 2.
- Generating Capacity: Each of the three CTG has a nominal generating capacity of 250 MW. Each of the three HRSG provides steam to the single steam turbine-electrical generator (STG), which has a nominal capacity of 500 MW. The nominal capacity of Unit 3 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 selective catalytic reduction (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 best available control technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

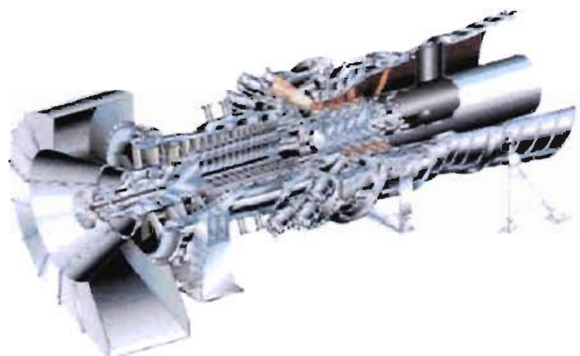
- Stack Parameters: Each HRSG has a combined cycle stack that is at least 149 feet tall with a nominal diameter of 23 feet. The following table summarizes the exhaust characteristics of each of the three CTG/HRSG sets, exclusive of the DB:

Table 1. Exhaust Characteristics of the CTG comprising Unit 3 at 100% Load and 59 °F

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp., °F	Exhaust Temp., °F	Flow Rate ACFM
Gas	2333 mmBtu/hour	59 °F	195 °F	1,330,197
Oil	2117 mmBtu/hour	59 °F	293 °F	1,553,502

Project 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 longitudinal section diagram of an M501G (rotor inside of casing) from a Mitsubishi Heavy Industries (MHI) brochure is shown in the left hand side of the figures below. The photograph on the right hand side of the figure is of the rotor being lowered into the shell (not visible) of an M501G. The compressor rotating blades are in the foreground and the 4-stage expansion section is in the background.



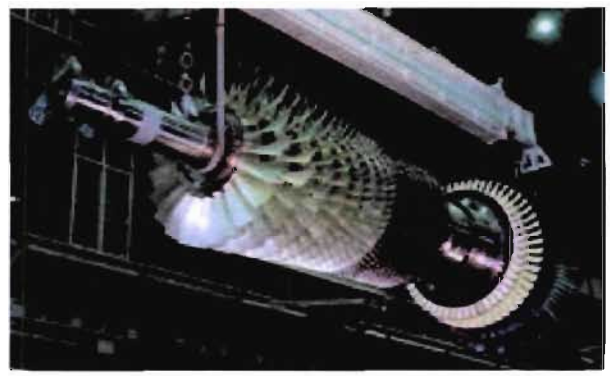


Figure 4. Longitudinal View of M501G, Photograph of Rotor (Source: MHI Website)

Ambient air is drawn into the 17-stage compressor of the M501G where it is compressed to a pressure ratio greater than 19 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate steam-cooled, can-annular, DLN combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is greater than 2,700 °F.

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 of approximately 1200 °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 5. 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.

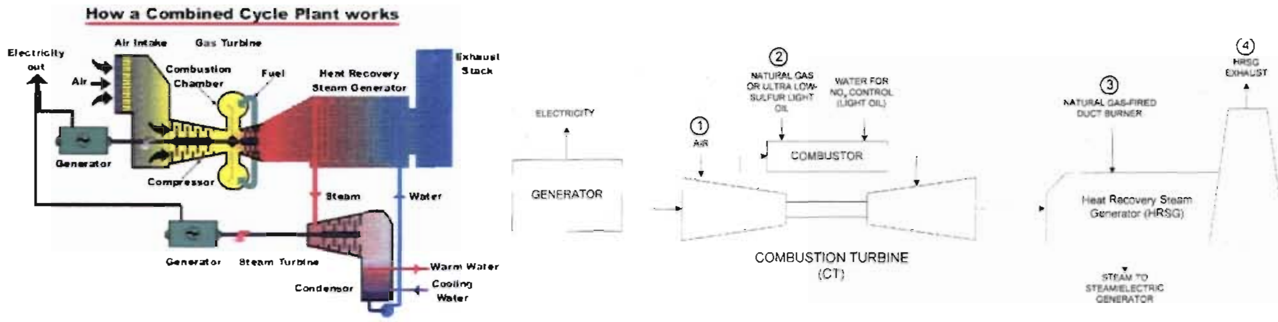


Figure 5. Natural Gas Fueled Combined Cycle Unit with DB and Backup ULSD FO

In combined cycle mode, the thermal efficiency of the G-Class CTG is approximately 58 percent (%) on the basis of LHV and about 53% based on the higher heating value (HHV).

- 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 more 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 2880 hours of duct burning per year for each HRSG.

Further process details are provided in the Draft BACT determination, Section 4.0 below.

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 (including PSD Requirements)
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

Description of PSD Applicability Requirements

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 WCEC 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. [Rule 62-210.200(185)(a)1., F.A.C.]

Because it has been established that the WCEC is a Major Stationary Source, PSD will apply to each pollutant for which there will be a net emissions increase greater than its respective significant emission rate (SER). The SER means a rate of pollutant emissions that would equal or exceed the values described in Rule 62-210.200(185)(a)1., F.A.C.

Potential Emissions

The following table is a summary of the estimated annual emissions from the WCEC Unit 3 project compared with the respective PSD SER. Emissions from Units 1 and 2 are included for information purposes.

Table 4. Projected Annual Emissions from WCEC Unit 3 Versus PSD SER Thresholds

Pollutant	Units 1 & 2 TPY	Unit 3 TPY	PSD SER TPY	PSD Review Required?	WCEC Total TPY
CO	1,038	521	100	Yes	1,559
Pb (lead)	0.055	0.022	0.6	No	0.067
NO_X	713	359	40	Yes	1,072
$PM/PM_{10}/PM_{2.5}$	501/277/277	250/139/139	25/15/*	Yes	751/416/416
SO_2	399	199	40	Yes	598
SAM	81	40	7	Yes	121
VOC	165	82	40	Yes	247

* $PM_{2.5}$ emissions are conservatively estimated to equal PM_{10}. There is not yet a SER for $PM_{2.5}$.

For each pollutant with a net emission increase from Unit 3 exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) as defined in Paragraph 62-210.200(39), F.A.C. to minimize emissions and conduct an ambient air quality analysis as applicable.

The required ambient air quality analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards (NAAQS) and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRV); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. [Rule 62-212.400(5) through (9), F.A.C.]

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Paragraph 62-210.200 (39), FAC as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. Energy, environmental and economic impacts, and other costs;

2. All scientific, engineering, and technical material and other information available to the Department; and

3. The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

According to Rule 62-212.400(4)(c), F.A.C., the applicant must at a minimum provide certain information in the application including:

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

According to Rule 62-212.400(10), F.A.C., the Department is required to conduct a control technology review and shall not issue any permit unless it determines that:

(a) The owner or operator of a major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.

(b) The owner or operator of a new major stationary source shall apply best available control technology for each PSD pollutant that the source would have the potential to emit in significant amounts.

(c) The owner or operator of a major modification shall apply best available control technology for each PSD pollutant which would result in a significant net emissions increase at the source. (This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.)

(d) The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C.

4.2 NO_X BACT Determination

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 6.

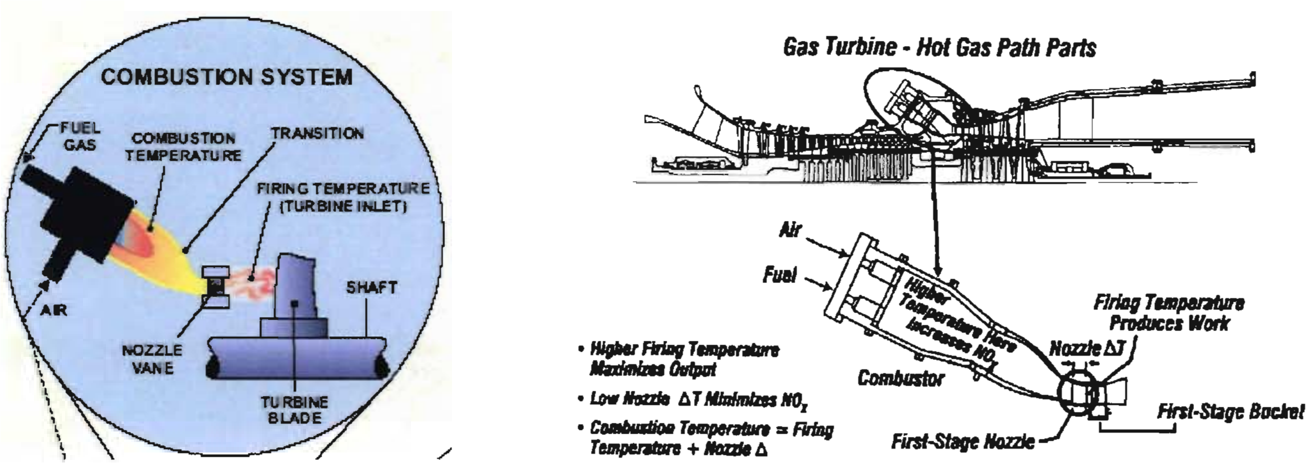


Figure 6. Relation between Combustion and Firing Temperatures and NO_X Formation

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 6, 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 shown on the left hand side of Figure 7. 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.

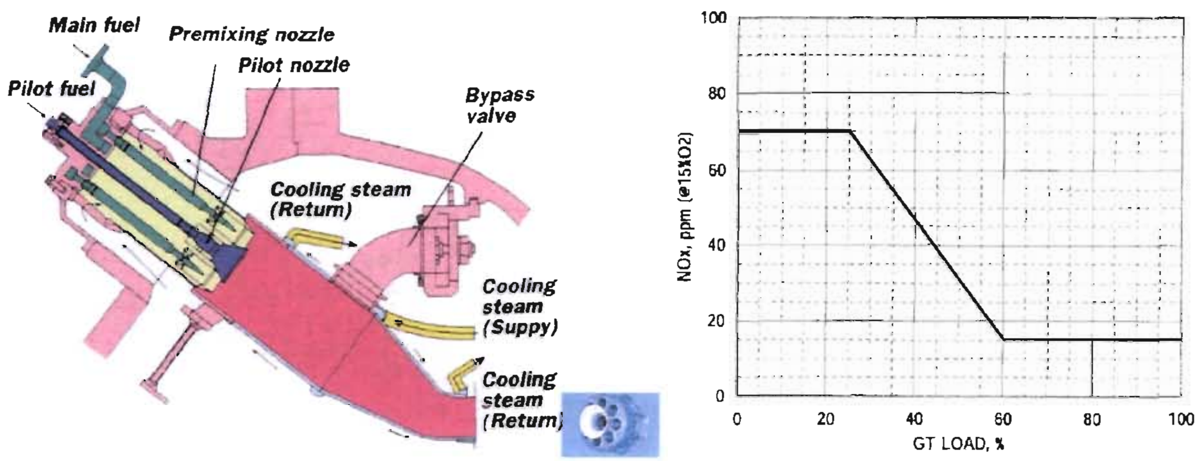


Figure 7. M501G DLN Combustor, Nozzle Block and NO_X versus Load Specification

The graph on the right hand side in Figure 7 contains the NO_X specifications for new Mitsubishi M501G1 CTG.[1] 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).

It is believed that the combustor for the M501G can actually 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.

Catalytic Combustion – XONON™. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[2] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system known as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki CTG equipped with XONON™.[3] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[4] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[5] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the FP&L West County Energy Center project.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (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:

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

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to NH_3 oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. SCR units are typically used in combination with wet injection or DLN combustion controls.

Figure 8 (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.

Figure 9 is a photograph of the PEF Hines Power Block 1. 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.

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.

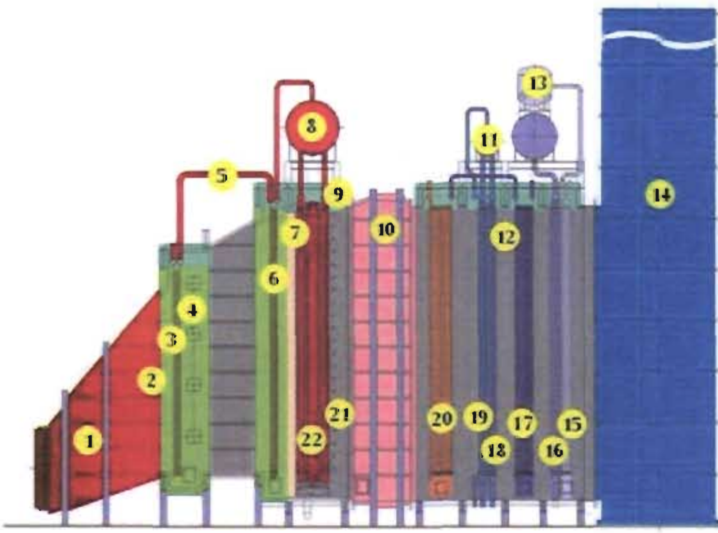


Figure 8 – Key HRSG Components (10 is SCR)

Figure 9 – PEF Hines Block I

The performance of SCR on a M501G combined cycle unit with DB at the Sithe Mystic Station (Massachusetts) is depicted in the following figure. The unit has a NO_X limit of 2 ppmvd @15% O_2.[6]

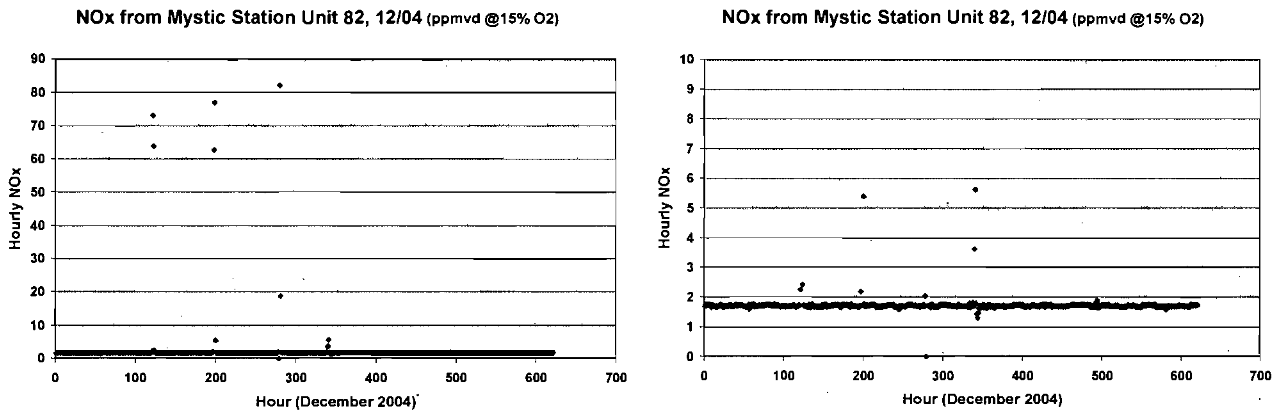


Figure 10. Hourly NO_X Data from Sithe Mystic Station, Massachusetts. December 2004

Unit 82 operated 620 hours during the month of December 2004, typically at CTG electrical generation rates between 170 and 250 MW. The data on the left comprise all reported hours of operation including thirteen measurements related to startups and shutdowns. The same data on the right, in greater resolution, clearly show that, with the exception of the startup and shutdown values, the unit consistently achieved less than 2 ppmvd NO_X @15% O_2.

Since 1999, SCR has been specified for all combined cycle projects in Florida that required a BACT determination. All of the projects rely on DLN or wet injection for basic NO_X control in addition to the add-on SCR systems.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle CTG projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order of 95 to 99%.

EMx (formerly $SCONO_X$) This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large CTG projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

EMx systems were installed at seven sites ranging in capacity from 5 to 43 MW.[7] None was installed at a large facility.

EMx technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. EMx has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. EMx systems also oxidize emissions of CO and VOC for additional emission reductions. EMx can match the performance of SCR without NH_3 slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

Table 5 contains averaged cost values for SCR with oxidation catalyst (SCR/CO) and for EMx developed by the California Air Resources Board for their Legislature.[8] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion CTG and one STG meeting BACT requirements.

Table 5. Cost Comparison between SCR and EMx for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	SCONO$_X$™	SCR/CO	SCONO$_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with EMx multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the EMx system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Initially, the key argument in favor of EMx was its ability to achieve low NO_X emissions without NH_3 emissions. In response, SCR suppliers offered systems that include an NH_3 destruction catalyst.[9] Even if the NH_3 catalyst adds 50% to the SCR/CO costs given above, it does not appear that EMx would be competitive.

Estimates provided by FP&L for the proposed 1,250 MW Unit 3 project also indicate a large cost difference between SCR and EMx. While the Department does not accept or reject either set of figures, it appears that EMx is not cost-effective for the present project.

Applicant's NO_X BACT Proposal

The applicant proposes a BACT NO_X limit of 2.0 ppmvd @15% O_2 for Unit 3 whether or not the DB are in use. This value is equal to the Department's final BACT determination issued for Units 1 and 2 in early 2007. FP&L proposes to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. FP&L proposed a BACT NO_X emission limit of 8 ppmvd @15% O_2 by a combination of wet injection and SCR while burning backup ULSD FO.

Department's Draft NO_X BACT Determinations

Table 6 includes the known determinations for M501G units. All used SCR.

Table 6. NO_X Standards for M501G Combined Cycle Units with DB

Project Location	Capacity (MW)	NO_X Limit and Fuel (ppmvd @ 15% O_2)	Comments
FP&L WCEC Unit 3	**1,250**	**2.0/8.0-NG/FO (24-hr)**	**Draft BACT, Startup ~2011**
FP&L WCEC Units 1&2	2,500	2.0/8.0–NG&DB/FO (24-hr)	BACT, Startup ~2009
Port Westward, OR	415	2.5 – NG & DB (3-hr)	BACT, Startup ~ 2007
Covert Generating, MI	1,200	2.5 – NG & DB (24-hr)	BACT, Startup 2004
Sithe Mystic, MA	1,600	2 – NG & DB (1-hr)	LAER, Startup 2003
Sithe Fore River, MA	800	2/6 – NG & DB/FO (1-hr)	LAER, Startup 2003
Wolf Hollow, TX	730	9 – NG (DB?)	BACT, Startup 2003

Notes: NG = Natural Gas DB = Duct Burner FO = Fuel Oil

Based on this table, the "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average for G-Class units. The data from the Sithe Mystic project provides reasonable assurance that a level of 2.0 ppmvd @15% O_2 can be consistently achieved.

The Department will set limits of 2.0 and 8.0 ppmvd @15% O_2 while firing natural gas (with or without use of DB) and for the limited firing of ULSD FO, respectively. Averaging times will be 24 hours.

The Department does not consider a 1-hour averaging time to be necessary to insure continuous low NO_X levels. This provides relief from some of the small risks of occasionally exceeding the very low BACT NO_X limits during an hour while not exceeding it when averaged over a day.

The Department reviewed compliance test data for the recently commissioned 1,100 MW FP&L Turkey Point Unit 5. Average NO_X emissions during the tests from the four CTG that comprise Unit 5 ranged from 1.36 to 1.70 ppmvd @15% O_2 while firing natural gas (whether or not the DB were used) even though their limit is 2.0 ppmvd @15% O_2 on a 24-hour basis.

The Department accepts FP&L's proposal of 2.0 ppmvd @15% O_2 with an averaging period of 24-hrs, and minimization of ULSD FO use to 500 hours as BACT for this project. The limit of 2.0 ppmvd @15% O_2 represents a further reduction of 87% compared with the recently promulgated New Source Performance Standard at 40 CFR 60, Subpart KKKK.

4.3 CO and VOC BACT Determination

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 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%.[10]

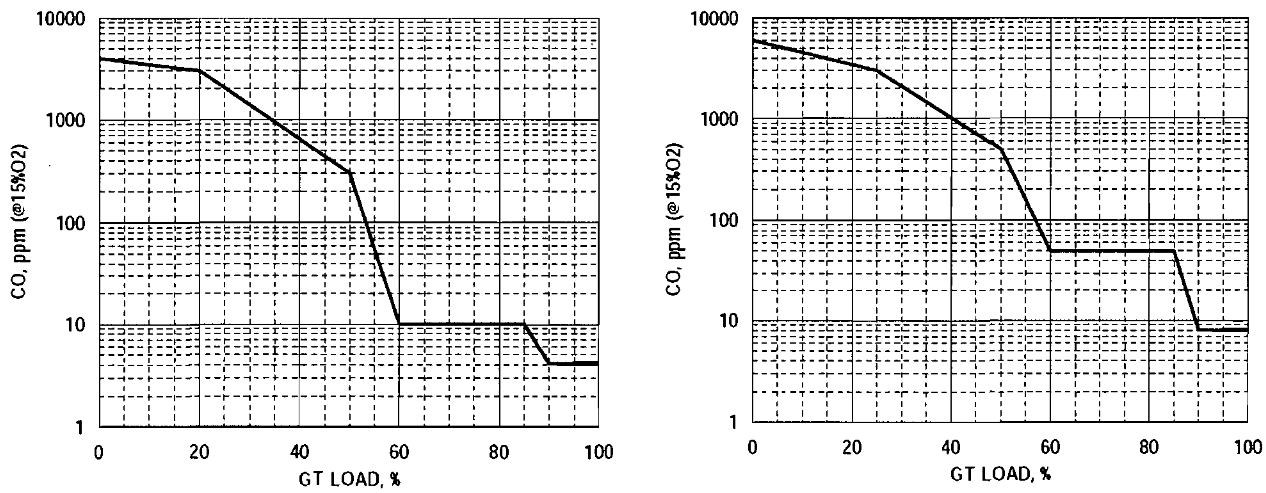


Figure 11. Expected CO versus Load while burning Gas or FO in a M501G

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 8, 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 8, 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 12 shows an individual burner and an array comprising a DB. The hot TEG serves as combustion air for gas introduced into the burner array.

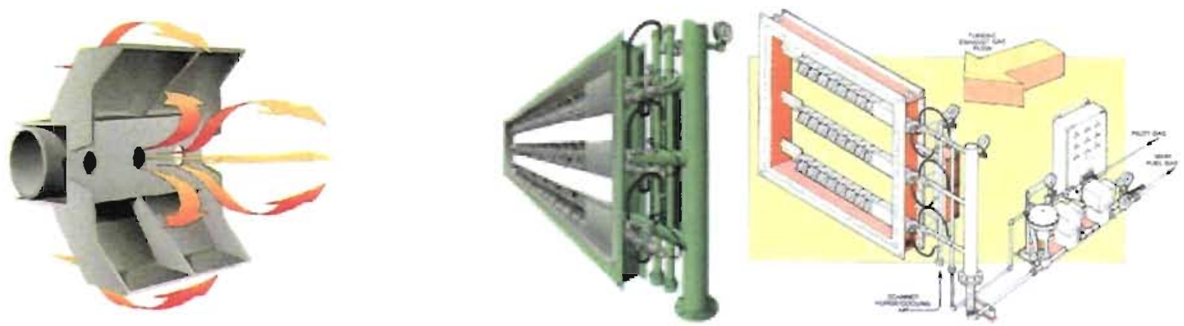


Figure 12 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

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.

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.

FP&L's CO and VOC BACT Proposal

FP&L has proposed BACT 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. FP&L proposes the emissions limits given in Table 7 as BACT for CO and VOC to account for all of the scenarios discussed above.

FP&L obtained high load (90-100%) guarantees from Mitsubishi of 4.1 and 8.0 ppmvd CO @15% O_2 for natural gas and FO firing, respectively. The guaranteed CO emission at medium load is 10 ppmvd CO @15% O_2 while firing natural gas. Per Figure 11, expected medium load emissions are 50 ppmvd CO @15% O_2 while firing FO.

Table 7. FP&L BACT Proposal for CO, VOC Emissions - WCEC Unit 3 (ppmvd@15% O_2)

Modes	CO	VOC
Natural Gas	4.1	1.2
Natural Gas & DB	7.6	1.6
ULSD FO	8.0	6.0
All Modes	8.0 (24 hours)	
All Modes	6.0 (12 months)	

Department's Draft CO and VOC BACT Determinations

The known CO and VOC (as well as PM, NH_3 and visible emissions) determinations for projects based on the M501G technology are presented in Table 8. FP&L's proposal for the WCEC Unit 3 project is included in the table for comparison.

Table 8. CO, VOC, PM Standards for M501G Combined Cycle Units with DB

Project Location	CO – ppmvd @15% O_2	VOC – ppmv (@15% O_2)	PM – lb/mmBtu or lb/hr NH_3 – ppmvd @15% O_2
FP&L WCEC Unit 3	**4.1/8–NG/FO (DB off, 100%, test) 7.6 – NG (DB on, 100%, test) 8.0 – All Modes, 24 hours 6.0 – All Modes, 12 months**	**1.2 – NG (DB off) 1.5 – NG (DB on) 6 – FO (DB off)**	**10% Opacity (NH_3 = 5 ppmvd)**
FP&L WCEC Units 1&2	4.1/8–NG/FO (DB off, 100%, test) 7.6 – NG (DB on, 100%, test) 8.0 – All Modes, 24 hours 6.0 – All Modes, 12 months	1.2 – NG (DB off) 1.5 – NG (DB on) 6 – FO (DB off)	10% Opacity (NH_3 = 5 ppmvd)
Sithe Mystic, MA	2.0 – NG & DB (1-hr, Ox-Cat)	1.0 (DB off) 1.7 (DB on)	0.011 (32.5 lb/hr) (NG+DB) (NH_3 = 2.0 ppmvd)
Sithe Fore River, MA	2/7–NG & DB/FO (1-hr, Ox-Cat)	1.0 (DB off) 1.7 (DB on)	0.011 (32.5 lb/hr) (NG+DB) 0.05 (140 lb/hr) (FO+DB) (NH_3 = 2.0 ppmvd)
Covert Generating, MI	5 (Ox-Cat, per MHI Paper)[11] According to Permit:[12] 33.7 lb/hr (NG+DB, 24-hr)	7.7 lb/hr (NG+DB)	33.8 lb/hr (NG+DB) (NH_3 = 10 ppmvd)
Wolf Hollow, TX	33.8 (NG+DB, 24-hr)	NI	PM = NI (NH_3 = 10 ppmvd)
Port Westward, OR	4.9 (NG+DB, 3-hr, Ox-Cat)	7.7 lb (NG+DB)	(NH_3 = 8 ppmvd)

Notes: NI = No Information NG = CT on Natural Gas DB = Duct Burner FO = Fuel Oil

The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

It is clear from Figure 11 that CO emissions from the M501G are very low at high load for the normal natural gas mode and the FO mode even without oxidation catalyst. FP&L estimates greater CO concentrations while using the DB burners than when operating the CTG at full load.

The Department reviewed compliance test data for the recently commissioned 1,100 MW FP&L Turkey Point Unit 5 that was subject to the identical limits proposed for the WCEC Unit 3. Average CO emissions during the tests from the four CTG that comprise Turkey Point Unit 5 ranged from 0.26 to 0.94 ppmvd @15% O_2 while firing natural gas (whether or not ULSD FO or the DB were used) even though the applicable limits are 4.1 to 8.0 ppmvd @15% O_2 on a 24-hour basis.

On a given day, each CTG/supplementary-fired HRSG can operate within the full spectrum of loads (60-100%) and fuels. FP&L and the Department have agreed that a continuous 24-hour emissions limit to cover all the modes of operation will be 8.0 ppmvd @15% O_2. This and the full load proposals are consistent with recent determinations for FP&L Turkey Point, FMPA Treasure Coast and OUC Stanton Unit B combined cycle projects.

Similarly an annual 12-month limit of 6 ppmvd will apply that takes into consideration the preponderance of natural gas operation at 4.1 ppmvd @15% O_2.

While FP&L has requested to use 500 hours per year of ULSD FO, they will rarely use it. For example Martin Combined Cycle Units 3 and 4 were permitted to fire both natural gas and FO, but were never even commissioned to fire FO.

With respect to the dual-fuel units, FP&L advised: *"Our historical practice has been that we run on oil for limited hours each month for reliability purposes (to ensure that the systems operate properly), and from time to time, we burn oil when gas service is interrupted or other factors require us to use back-up fuel. Martin Unit 8 (2005), Fort Myers Units 3A and 3B (since 2003), Fort Lauderdale Units 4 & 5 (since 1996) and Putnam (since 1996) collectively averaged less than 100 hours of oil burning per year per unit."*[13]

The Department agrees that FP&L's description is a reasonable expectation for the proposed West County Power Plant. Given the low FO use and restrictive daily and annual CO <u>stack</u> emission concentrations, there is little benefit in installing oxidation catalyst.

For reference, FP&L submitted respective cost-effectiveness estimates of \$8,700 and \$87,164 per ton of CO and VOC removed when using oxidation catalyst. The Department does not necessarily accept or reject the cost estimates but agrees that oxidation catalyst is not cost effective for this project.

FP&L successfully obtained the lowest guarantees for "G" technology units specified to-date prior to consideration of additional control by catalyst. FP&L can install an oxidation catalyst at a future date to meet the low CO emission limits if circumstances such as very high natural gas prices cause greater operation at low load conditions characteristic of higher CO concentrations.

The Department concurs with the VOC BACT proposal while burning natural gas of 1.2 and 1.5 ppmvd @15% O_2 with the DB off and on, respectively. The Department also concurs with the VOC BACT proposal of 6.0 ppmvd @15% O_2 while burning ULSD FO. VOC emissions while burning ULSD FO will typically be less than 1 ppmvd @15% O_2 for high load and less than 5 ppmvd @15% O_2 for medium load, respectively, during the brief periods of ULSD FO.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde (CH_2O) emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the CH_2O limit of Part 63, Subpart YYYY - NESHAP for Stationary Combustion Turbines.

4.4 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

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 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 as BACT the use of ULSD FO (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF). For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to CTG is 0.8% by weight.

FP&L estimated 199 tons per year of SO_2 and 40 tons per year of sulfuric acid mist (SAM) per this combined cycle unit. 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 standard cubic foot (SCF) than to 2 gr/100 SCF. The Department accepts FP&L's BACT proposal for SO_2 and SAM. This approach is consistent with other recently permitted projects.

4.5 Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT Determination 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 will be limited to less than 500 hours per year 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. The BACT process limits the nitrate and sulfate formation potential of the CTG and DB exhaust. 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.

Cooling Tower PM Emissions

The applicant's preliminary design includes a 26-cell mechanical draft cooling tower for Unit 3 with the following nominal specifications: a circulating water flow rate of 304,000 gallons per minute (gpm); design hot/cold water temperatures of 92 °F/76 °F; a design air flow rate of 1,360,000 actual cubic feet per minute (acfm) per cell; a liquid-to-gas air flow ratio of 1.13; and drift eliminators with a drift rate of no more than 0.0005 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water.

FP&L estimates maximum annual PM and PM_{10} emissions from the cooling tower of 117 and 5 TPY respectively.

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

FP&L proposes $PM/PM_{10}/PM_{2.5}$ BACT as an opacity limit of 10% in conjunction with the use of inherently clean fuels. FP&L proposes PM control from the cooling tower to be accomplished by a 0.0005% drift rate design limitation.

Department's Draft $PM/PM_{10}/PM_{2.5}$ BACT Determinations

The following conditions are established as the draft BACT 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. The CTG may fire ULSD FO as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- NH_3 emissions (slip) shall not exceed 5 ppmvd.
- The cooling tower shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

4.6 New Source Performance Standards Applicable to CTG and DB

Stationary CTG are subject to the recent federal NSPS in Subpart KKKK of 40 CFR 60. These requirements result in the following standards for the proposed CTG including the DB located in the HRSG. The limits are:

- NO_X (gas) ≤ 15 ppm @ 15% O_2 or 0. 43 lb/MWh (4-hr average);
- NO_X (oil) ≤ 42 ppm @ 15% O_2 or 1.3 lb/MWh (30 operating day average); and
- SO_2 ≤ 0.90 lb/MWh or ≤ 0.060 lb SO_2/MMBtu

Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring by demonstrating sulfur content of no more than 0.05% by weight FO or 20 gr/100 SCF of natural gas. The Department's BACT determinations are significantly more stringent than the requirements of 40 CFR 60, Subpart KKKK. The short term nature of the NO_X limit under Subpart KKKK will necessitate an additional 4-hour limitation in the permit. Subpart KKKK also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations.

4.7 Department Draft BACT Determinations for CTG and DB

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

Table 9. Draft BACT Determination

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	CTG	8.0	42.0	8.0, 24-hr 6, 12-month [h]
	Gas	CTG & DB	7.6	52.5	
		CTG Normal	4.1	23.2	
NO_X [b]	Oil	CTG	8.0	82.4	8.0, 24-hr
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr <u>and</u> 15, 4-hr [h]
		CTG Normal	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur FO		
VOC [e]	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
		CTG Normal	1.2	4.1	
NH_3 [f]	Oil/Gas	CTG, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, FO, and basic DB mode. The stacks test limits apply only at high load (90-100% of the CTG capacity).

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for 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).

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the CTG and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. 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. The limits apply only at high load (90-100% of the CTG capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

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

h. The 4-hr, 15 ppmvd NO_X limitation is from Subpart KKKK and is in addition to the 2.0 ppmvd NO_X BACT limits.

4.8 National Emission Standards for Hazardous Air Pollutants Applicable to CTG

The WCEC will be a new major source of HAP. As such, the proposed new CTG would be subject to 40 CFR 63, Subpart YYYY, which became final on March 5, 2004.[14]. According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new CTG would be subject to an emissions standard for CH_2O of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2).

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[15] EPA has stayed the applicability of YYYY to units such as those proposed for the WCEC project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

4.9 BACT Determinations for Emergency Generators

Two standby emergency generators are included for Unit 3. These will be used when electricity is not available to the site, such as during hurricanes. Following are the specifications of the proposed emergency generators:

- Model is Caterpillar 3516BTA;
- Usage of 500 hours per year;
- 16 cylinders;
- Displacement of 4.3125 liters per cylinder;
- Engine rated at 3,200 Brake Horse Power (BHP); and
- Generator rated at 2,250 kW.

On July 11, 2006 EPA issued Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ICE).[16] The values applicable to generators sets in the size category of the emergency generators proposed by FP&L are given in the following table.

Table 10. Emission standards for 2007–2010 model year engines >2,237 kW (3,000 HP) and with a displacement of <10 liters per cylinder in grams/BHP-hr.

CO	Hydrocarbons	NO_X	PM
8.5	1.0	6.9	0.4

The Department accepts the values given for emergency ICE as BACT in conjunction with use of ULSD FO. Use of ULSD FO will result in substantially less PM than indicated above and will also minimize PM_{10}, and $PM_{2.5}$ emissions and precursors.

As emergency generators, these units will be subject to the notification requirements of 40 CFR 63, Subpart ZZZZ – NESHAP for Reciprocating Internal Combustors Engines.

4.10 BACT Determinations for Natural Gas Heaters

Two natural gas heaters are required for the project. The purpose of these units is to heat natural gas above dew point temperature and prevent condensation.

FP&L described the specifications for the gas heaters are as follows:

- Hannover Compression Company or equivalent;
- Continuous use although actual use will be much less; and
- Maximum heat input rate of 10 MMBtu/hr heat input.

Table 11. Proposed Emissions from Natural Gas-fired Fuel Heaters

SO_2	NO_X	CO	VOC	PM
2 gr/100 SCF	0.095 lb/mmBtu	0.08 lb/mmBtu	0.005 lb/mmBtu	0.002 lb/mmBtu

The Department accepts the proposed emission values given for the natural gas-fired fuel heaters as BACT. According to an interpretive memorandum by EPA in response to a Department inquiry, gas heaters in the subject size category are subject to 40 CFR 60, Subpart Dc.

Natural gas heaters were subject to 40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters. Subpart DDDDD was vacated on July 30, 2007 by the U.S. Court of Appeals for the District of Columbia Circuit.

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 BACT 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. STG/HRSG startups occur as little as once during a ten-year period.

Based on information from FP&L regarding startup and shutdown, the Department establishes the following conditions for excess emissions for the CTG/HRSG system.

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, excess emissions NO_X and CO 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.

- *STG/HRSG System Cold Startup*: For cold startup of the STG/HRSG, excess NO_X and CO emissions from 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.
- *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.
- *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, excess NO_X and CO emissions 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.
- *Fuel Switching*: For fuel switching, excess NO_X and CO emissions shall not exceed two (2) hours in any 24-hour period.
- For startup, NH_3 injection shall begin as soon as the system reaches the manufacturer's specifications.
- 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.

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. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The proposed project, West County Energy Center (WCEC) Unit 3, will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM and VOC. VOC and NO_X are ozone precursors and any net increase of 100 tons per year of either pollutant requires an ambient air impact analysis including the gathering of preconstruction ambient air quality data.

Although the proposed project is for Unit 3 at the West County Energy Center site, the Department required that the applicant provide an ambient air quality impact analysis for all three units, Units 1, 2 and 3, since Units 1 and 2 are currently under construction. All results, conclusions and analyses detailed below are for Units 1, 2 and 3 combined.

6.2 Major Stationary Sources in Palm Beach County

The current largest stationary sources of air pollution in Palm Beach County are listed below. The information is from annual operating reports submitted to the Department.

Table 12. Major Sources of NO_X in Palm Beach County (2006)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	3,077
Palm Beach County SWA	Resource Recovery Facility	1,156
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**1,072**
New Hope Power Partnership	Okeelanta Cogeneration Plant	822
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	641
U.S. Sugar Corp.	Bryant Mill	361
United Technologies Corp.	Pratt & Whitney Aircraft	358
Osceola Farms	Osceola Farms	321

Table 13. Largest Sources of SO_2 in Palm Beach County (2006)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	5,238
Florida Power & Light	**WCEC – Units 1, 2 and 3**	598
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	477
Palm Beach County SWA	Resource Recovery Facility	254
New Hope Power Partnership	Okeelanta Cogeneration Plant	166
Osceola Farms	Osceola Farms	106

Table 14. Largest Sources of PM_{10} in Palm Beach County (2006)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	460
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**416**
US Sugar Corporation	Bryant Sugar Mill	290
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	278
Osceola Farms	Osceola Farms	234
Palm Beach County SWA	Resource Recovery Facility	79

Table 15. Largest Sources of CO in Palm Beach County (2006)

Owner	Site Name	Tons per year
U.S. Sugar Corp.	Bryant Mill	13,402
Osceola Farms	Osceola Farms	7,093
New Hope Power Partnership	Okeelanta Cogeneration Plant	1,753
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**1,559**
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	1,030
Palm Beach County SWA	Resource Recovery Facility	636
Florida Power & Light	Riviera Power Plant	593

Table 16. Largest Sources of VOC in Palm Beach County (2006)

Owner	Site Name	Tons per year
US Sugar Corporation	Bryant Sugar Mill	789
Osceola Farms	Osceola Farms	537
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	426
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**247**
New Hope Power Partnership	Okeelanta Cogeneration Plant	62
George Weston Bakeries, Inc.	Arnold and Thomas Bakery	60

6.3 Air Quality and Monitoring in the Palm Beach County

The Palm Beach County Health Department operates eleven monitors at seven sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, NO_2 and SO_2. The 2007 monitoring network is shown in the figure below.

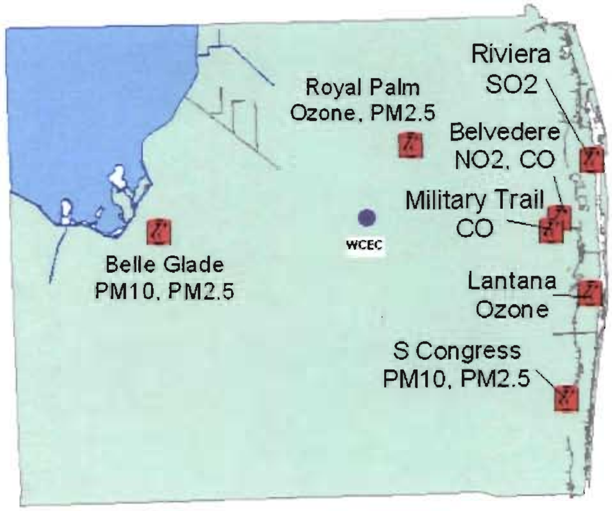


Figure 13. Palm Beach County Health Department Ambient Air Monitoring Network

Measured ambient air quality information is summarized in the following table.

Table 17. Ambient Air Quality in Palm Beach County Nearest to Project Site (2007)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Belle Glade	24-hour	60	37		150 [a]	µg/m^3
		Annual			17	50[b]	µg/m^3
$PM_{2.5}$	Royal Palm Beach	24-hour	57	38		35[c]	µg/m^3
		Annual			7[g]	15[d]	µg/m^3
		98th Percentile	18.6				µg/m^3
SO_2	Riviera Beach	3-hour	4	4		500[e]	ppb
		24-hour	2	2		100[e]	ppb
		Annual			1	20[b]	ppb
NO_2	Palm Beach	Annual			8	53[b]	ppb
CO	West Palm Beach Military Trail	1-hour	3	2		35[e]	ppm
		8-hour	1	1		9[e]	ppm
Ozone	Royal Palm Beach	1-hour	0.079	0.078		0.12[a]	ppm
		8-hour	0.069	0.068		0.08[f]	ppm

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. mean does not satisfy summary criteria for 2007

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 redesignation and classification, possibly in 2009, the areas shown in the following figure will no longer be in attainment with the applicable ozone AAQS. Palm Beach County will remain in attainment with the new ozone standard.

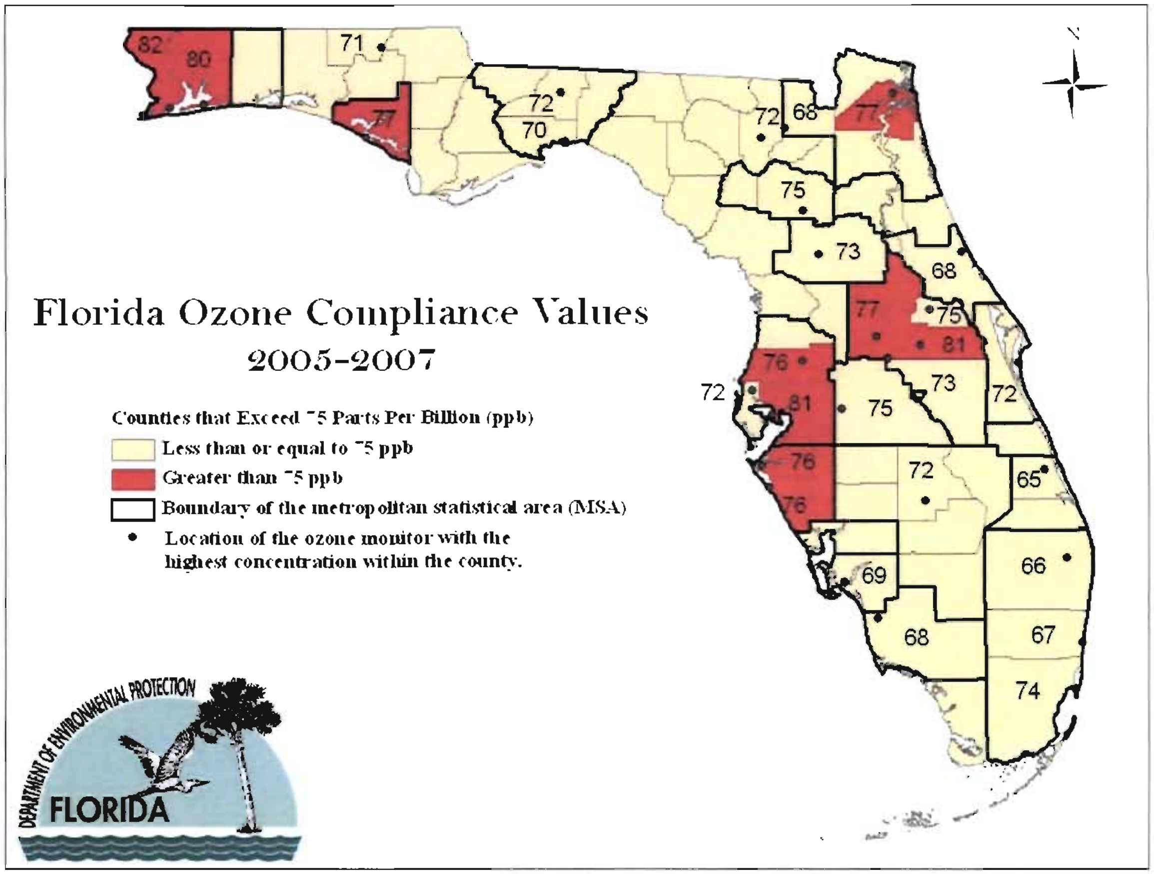


Figure 14. Map indicating Areas Registering an ozone Value Greater than 75 ppb.

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels, at least at the monitoring locations. One exception is ozone because it is formed from precursors that are clearly available (NO_X and VOC) from local industrial and transportation emissions. The tendency to form ozone is accentuated by hot ambient temperature, solar insolation, high pressure, and relatively low wind speed. Such conditions when combined with cyclical drought or Everglades fires have the greatest potential to cause ozone exceedances.

Although low CO concentrations are recorded at the single monitor located on Military Trail, it is likely that CO concentrations will occasionally be greater in the area of sugar cane farming and milling due to fires and inefficient combustion of moist bagasse.

6.4 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SIL) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class I Everglades National Park (ENP) and the PSD Class II Area (everywhere except the ENP). Further, the Class II area includes the Loxahatchee National Wildlife Refuge.

For the Class II analysis, 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. From 5 to 7 kilometers, Cartesian receptors with a spacing of 500 meters were used and from 7 to 10 kilometers, a spacing of 1000 meters was used.

Receptors within the grid described above may be eliminated if they fall on property that is inaccessible to the public. Modeling impacts are only measured in areas of "ambient air" or where the public has access. For this proposed project, Palm Beach Aggregates leases a public restricted property in the vicinity of the WCEC site. Within this property, Palm Beach Aggregates, along with three additional minor sources of pollutants, are in operation. Therefore, the receptors on this restricted property were eliminated for the analysis.

For the Class I analysis, 901 discrete receptors located at the ENP were used. These receptors represent a subset of receptors provided by the National Park Service (NPS).

If this modeling at worst-load conditions shows ground-level increases less than the SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are greater than the applicable SIL for the Class II area (i.e. all areas except ENP) except for SO_2 on a 3-hour basis and CO. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 18. Maximum Predicted Air Quality Impacts from FPL West County Energy Center for Comparison to the PSD Class II SIL

Pollutant	Averaging Time	Max Predicted Impact (μg/m³)	Significant Impact Level (μg/m³)	2007 Baseline Concentrations (μg/m³)	Ambient Air Standards (μg/m³)	Significant Impact?
SO_2	Annual	1.3	1	~3	60	YES
	24-Hour	9.8	5	~5	260	YES
	3-Hour	16	25	~10	1300	NO
PM_{10}	Annual	1.6	1	~17	50	YES
	24-Hour	14	5	~60	150	YES
CO	8-Hour	50	500	~1150	10,000	NO
	1-Hour	74	2000	~3450	40,000	NO
NO_2	Annual	1.6	1	~15	100	YES

It is clear that maximum predicted impacts from the project are much less than the respective AAQS. SO_2 on a 3-hr basis and CO are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 102 km to the south of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from SO_2, PM_{10}, and NO_2 are equal to or less than the applicable SIL for the Class I area. Therefore, no further detailed modeling efforts are required for these pollutants.

Table 19. Maximum Predicted Air Quality Impacts from the FPL West County Energy Center for Comparison to the PSD Class I SIL at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (μg/m³)	Class I Significant Impact Level (μg/m³)	Significant Impact?
PM_{10}	Annual	0.004	0.2	NO
	24-hour	0.3	0.3	NO
NO_2	Annual	0.006	0.1	NO
SO_2	Annual	0.007	0.1	NO
	24-hour	0.1	0.2	NO
	3-hour	0.5	1	NO

<u>Preconstruction Ambient Monitoring Requirements</u>

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant used the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels except for PM_{10} on a 24-hour basis. Therefore, no pre-construction monitoring is required for those pollutants except for PM_{10} on a 24-hour basis.

Table 20. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Baseline Concentrations ($\mu g/m^3$)	Impact Greater Than De Minimis?
PM_{10}	24-hour	14	10	~60	YES
NO_2	Annual	1.6	14	~15	NO
SO_2	24-hour	10	13	~5	NO
CO	8-hour	50	575	~1150	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC and NO_x emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_x emissions from the project to be 247 and 1,072 tons per year respectively. Therefore, preconstruction monitoring for ozone is required.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for SO_2 on a 24-hour and annual basis, PM_{10} and NO_2 in the Class II area;
- A Preconstruction Monitoring analysis for 24-Hour PM_{10} and ozone;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. 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 (PBI) Airport and Florida International University in Miami 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 more conservative with regards to comparing surface parameters at PBI 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.

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 2001, 2002 and 2003.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. The maximum predicted SO_2 on a 24-hour and annual basis, PM_{10} and NO_2 PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of the West County Energy Center are shown in the following table.

Table 21. PSD Class II Increment Analysis

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	24	30	NO
	Annual	4	17	NO
SO_2	24-hour	29	91	NO
	Annual	5	20	NO
NO_2	Annual	8	25	NO

AAQS Analysis

For pollutants subject to an AAQS review, 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 the table below. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Table 22. Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2004- 2006 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	27	42	69	NO	150
	Annual	7	20	27	NO	50
SO_2	24-hour	36	8	44	NO	260
	Annual	13	3	16	NO	60
NO_2	Annual	43	21	64	NO	100

Ozone

Ozone is an area-wide pollution problem 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). According to the applicant, in 2005, Palm Beach County had total emissions of NO_X and VOC from stationary and mobile sources of 55,000 and 54,600 TPY respectively.

The West County Energy Center will add 247 and 1,072 TPY of VOC and NO_X respectively. The proposed facility will have very low emissions per unit of energy produced, but will still contribute appreciably to regional NO_X loading. VOC emissions will add less than 1% of regional VOC emissions.

In the near future, many existing power plants and other industries that contribute to visibility impairment will reduce emissions of NO_X and SO_2 pursuant to the Clean Air Interstate Rule (CAIR) and the requirements of Best Available Retrofit Technology (BART). A number of the plants included in the CAIR and BART process are located in the Tri-County Area (Miami-Dade, Broward, and Palm Beach Counties).

To conclusively prove whether or not the 1,072 tons of NO_X and 247 tons of VOC will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. The uncertainty in any regional ozone model would be greater than the contribution from this project.

Preconstruction Monitoring Analysis for 24-hour PM_{10} and Ozone

The applicant provided a monitoring analysis for ozone and PM_{10} for the area of Palm Beach County closest to the project site. There is an ozone monitoring site 8 miles to the east of the project site and a PM_{10} monitor 17 miles to the west of the project site. Both of which are close to the proposed project and are representative of the air quality in the vicinity of the project. Therefore, placing preconstruction monitors at the project site is not needed, nor required to obtain background air quality concentrations.

The air quality in the vicinity of the project is detailed in above sections. The county is in attainment for both ozone and PM_{10}. PM_{10} modeling also shows that the proposed project will not contribute to a violation of the standard.

6.5 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from the natural gas and ultralow sulfur diesel fuel oil that is fired in gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS.

Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation and wildlife will be minimal or insignificant. The following example is instructive.

According to the applicant, lichens are a plant species in the area of the project that are sensitive to air pollutants. Annual SO_2 levels of 8 $\mu g/m^3$ can lead to adverse impacts. SO_2 impacts from the West County Energy Center will be much less than these levels and therefore, will not contribute to adverse impacts on vegetation such as lichens.

Air pollutants can also adversely impact wildlife. According to the application, guinea pigs have respiratory stress when exposed to levels of 96 $\mu g/m^3$ of nitrogen oxides on an annual basis. Long-term NO_2 levels predicted from the West County Energy Center will be well below this level and therefore, will not contribute to adverse impacts on wildlife, such as guinea pigs.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are less than the significant impact levels (0.01 kg/ha/yr) determined by the NPS.

According to the applicant, the predicted deposition rates of sulfur and nitrogen of 0.0059 and 0.0036 kg/ha/yr respectively, impacts are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

The low NO_X limit coupled with the use of ultra low sulfur fuel oil and inherently clean natural gas will minimize any possible effects due to sulfur and nitrogen deposition. Additionally the fuels are extremely low in mercury content. The very low sulfur deposition rate from the proposed project will also minimize activation of mercury in the soils by sulfur reducing bacteria.

Impact on Visibility:

The applicant submitted a regional haze analysis for the ENP. The analysis included modeling from the CALPUFF model.

Despite FPL's initial BACT proposals to minimize SO_2, NO_X, and PM, the CALPUFF model predicts modeled impacts above the 5% visibility impairment based on criteria from the NPS. If the facility continuously operates on fuel oil, impairment can occur during 6 days in three years. Because of the limitation in fuel oil use, the probability that the meteorology on a given day which lead to visibility impairment will coincide is low and the most probable expectation is that there will be no days of visibility impairment over a period of three years. Visibility impairment while firing natural gas is less than when firing fuel oil.

The NPS was provided the opportunity to comment regarding the aforementioned AQRV analysis, including visibility, for this project. After their review, the NPS stated that "we are not concerned about the level of impacts on resources at the Everglades National Park." The Department did not receive comments from the U.S. Fish and Wildlife Service regarding the Class I or Class II impacts from this project.

Growth-Related Impacts Due to the Proposed Project:

According to the applicant, there will be short-term increases in the labor force to construct the project. According to the applicant, about 350 additional workers will be needed over the 24-month construction period. Operation of the new facility will require 10-15 permanent employees.

The project is a response to state-wide and regional electrical demand growth and is one of several projects identified by FPL for its service area within its annual 10 year plans submitted to the Public Service Commission.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, population growth in the area of the proposed project, Palm Beach County, has increased 155% from 1977 to 2005. The number of residential households has also increased in the county, 113% from 1977 to 2005. Transportation in the county also grew in terms of vehicle miles traveled by 95 percent over the same time period. Between 1977 and 2000, the number of those employed in the county grew about 234%.

The applicant addressed industrial growth in Palm Beach County as well. According to the applicant, the manufacturing industry has seen a slight decrease in employment from 1977-2005, however, the agricultural industry saw about a 329% increase in employees (1977-2005). Existing Utility Facilities in Palm Beach County include the FPL Riviera Facility and Lake Worth Utility.

Despite the growth in Southeast Florida, air quality has improved as evidenced by the redesignation of the Tri-County (Broward, Miami-Dade, and Palm Beach) area to attainment status with respect to the ozone standard.

7. Preliminary Determination

The Department makes a preliminary determination that the proposed 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 PSD application, reasonable assurances provided by the applicant, the draft BACT determinations, review of the air quality impact analysis, and the conditions specified in the draft permit.

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. Alvaro Linero is the project engineer responsible for preparing the draft BACT determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

REFERENCES

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PERMITTEE:

Florida Power and Light Company (FP&L)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

FP&L West County Energy Center
DEP File No. 0990646-002-AC
Permit No. PSD-FL-396
SIC No. 4911
Expires: December 31, 2013

PROJECT AND LOCATION

This permit authorizes the construction of the third nominal 1,250 megawatt combined cycle unit (Unit 3) and ancillary equipment at the Florida Power and Light Company (FP&L) West County Energy Center.

The proposed project will be located at 20505 State Road 80, Loxahatchee, Florida 33470. The UTM coordinates are Zone 17; 562.19 kilometers East; 2953.04 kilometers 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 project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. 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

The FP&L West County Energy Center (WCEC) was previously approved for construction as a nominal 2,500 megawatt (MW) greenfield power plant. The previously approved construction underway is for two nominal 1,250 MW gas-fired combined cycle units (Units 1 and 2) that will use ultralow sulfur diesel (ULSD) fuel oil (FO) as backup fuel.

Units 1 and 2 will each consist of: three nominal 250 megawatt (MW) Model 501G combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors; one nominal 428 mmBtu/hour (lower heating value - LHV) gas-fired duct burner (DB) located within each of the three HRSG; three 149 feet exhaust stacks; one 26 cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator (STG).

Previously approved ancillary equipment under construction and installation includes: four emergency generators; two natural gas fired fuel heaters; one emergency diesel fired pump; two diesel fuel storage tanks; two auxiliary steam boilers; and other associated support equipment.

This permit authorizes construction of another 1,250 MW gas-fired combined cycle unit (Unit 3) identical to the description given above for Units 1 and 2. Additional ancillary equipment for Unit 3 will include two emergency generators, two natural gas fired fuel heaters and associated equipment. Unit 3 will use some of the infrastructure and ancillary equipment already under construction including the diesel storage tanks and auxiliary boilers.

{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
013	Unit 3A – one nominal 250 MW CTG with supplementary-fired HRSG
014	Unit 3B – one nominal 250 MW CTG with supplementary-fired HRSG
015	Unit 3C – one nominal 250 MW CTG with supplementary-fired HRSG
016	One 26 cell mechanical draft cooling tower
017	Two nominal 10 MMBtu/hr natural gas-fired process heaters
018	Two nominal 2,250 KW (~ 21 MMBtu/hr) emergency generators

REGULATORY CLASSIFICATION

The facility will be a major Prevention of Significant Deterioration (PSD) stationary source in accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.). Unit 3 is subject to the PSD rules including a determination of best available control technology (BACT).

The facility 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) or because it is a Major Source of hazardous air pollutants (HAP). 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 facility under construction is subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). Unit 3 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 additional emergency generators are subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines. Two additional process heaters are subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

The facility under construction is a major source of hazardous air pollutants (HAP) and is subject to several subparts under 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP). Unit 3 is potentially subject to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired CTG such as planned for this project.

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

The facility will be 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 facility under construction was certified under the Florida Power Plant Siting Act, 403.501-518, F.S. and Chapter 62-17, F.A.C. The Unit 3 project is subject to a modification of the certification.

APPENDICES

The following Appendices are attached as part of this permit.

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

Appendix BD: Final BACT Determinations and Emissions Standards.

Appendix GC: General Conditions.

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

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

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

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix YYYY: NESHAP Requirements for Gas Turbines, 40 CFR 63, Subpart YYYY.

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 and supplemental information received on December 6 and December 21, 2007;
- Department's request for additional information (RAI) January 4, 2008;
- Response to RAI received March 14, 2008; and
- Draft permit package issued on April 25, 2008.

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, BD, Dc, GC (General Conditions), IIII, KKKK, SC, XS, YYYY 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. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD 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, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

8. 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. COMBINED CYCLE UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 013, 014, and 015)

This section of the permit addresses the following emissions units.

Combined Cycle Unit 3 and associated equipment

Description: Combined Cycle Unit 3 will be comprised of emissions units (EU) 013, 014, and 015. Each EU will consist of: a Model M501G 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 250 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. The total nominal generating capacity of the facility is 3,750 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. The following summarizes the exhaust characteristics without the DB:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	2,333 MMBtu/hour	59° F	195° F	1,330,197
Oil	2,117 MMBtu/hour	59° F	293° F	1,533,502

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. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rule 62-212.400(BACT), F.A.C.]

2. 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 BACT emissions performance requirements 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.

3. NESHAP Requirements: The combustion turbines are subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY and Appendix A, NESHAP Subpart A of this permit).

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines-Electrical Generators (CTG): The permittee is authorized to install, tune, operate, and maintain three Model 501G CTG each with a nominal generating capacity of 250 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]

5. 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 (3A to 3C) and deliver steam to the steam turbine-electrical generator (STG). Each HRSG may be equipped with a gas-fired duct burner (DB) having a nominal heat input rate of 428 MMBtu per hour (LHV).

6. 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. The permittee may install the oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 12.h.

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.

[Design and Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

7. Permitted Capacity – Combustion Turbine-Electric Generators (CTG): The nominal heat input rate to each CTG is 2,333 MMBtu per hour when firing natural gas and 2,117 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.]

8. Permitted Capacity - HRSG Duct Burners (DB): The total nominal heat input rate to the DB for each HRSG is 428 MMBtu per hour based on the LHV of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

9. 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. Each CTG shall fire no more than 500 hours of fuel oil, during any calendar year.
[Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. 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) and 62-212.400 (BACT), F.A.C.]

11. 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; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

12. Emissions Standards: Emissions from each CTG/DB shall not exceed the following BACT standards. Compliance with the BACT limits also insures compliance with the emission limitations in Subpart KKKK.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	CTG	8.0	42.0	8.0, 24-hr
	Gas	CTG & DB	7.6	52.5	6, 12-month [h]
	Gas	CTG Normal Mode	4.1	23.2	
NO_X [b]	Oil	CTG	8.0	82.4	8.0, 24-hr
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr and 15, 4-hr
	Gas	CTG Normal Mode	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur FO		
VOC [e]	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
	Gas	CTG Normal Mode	1.2	4.1	
NH_3 [f]	Oil/Gas	CTG, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, FO, and basic DB mode. The stacks test limits apply only at high load (90-100% of the CTG capacity).

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for 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).

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the CTG and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. 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. The limits apply only at high load (90-100% of the CTG capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

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

h. The 4-hr, 15 ppmvd NO_X limitation is from Subpart KKKK and is in addition to the 2 ppmvd NO_X BACT limits.

[Rule 62-212.400(BACT), 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. 12 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.}

13. Operating Procedures: The BACT determinations 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) and 62-212.400(BACT), F.A.C.]

14. 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. [Rule 62-212.400(BACT), F.A.C.]

15. 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.]

16. 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.]

17. Excess Emissions Allowed: As specified in this condition, 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, excess emissions of NO_X and CO 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 STG/HRSG, excess NO_X and CO emissions from 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 Combined Cycle Operation*: For shutdown of the combined cycle operation, excess NO_X and CO emissions from 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, excess NO_X and CO emissions 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, excess NO_X and CO emissions shall not exceed two (2) hours in any 24-hour period.

18. 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 62-212.400(BACT) and 62-210.700, F.A.C.]

19. 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 14 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

20. 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

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]

21. 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]

22. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour 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. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

23. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emission standards for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual 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 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. 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 30, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. 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 of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NO_X 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.

26. 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. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

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

e. *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. 17 and 19 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.

f. *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) and 62-212.400(BACT), F.A.C.]

27. <u>Ammonia Monitoring Requirements:</u> 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) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

28. 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. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. 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) and 62-212.400(BACT), F.A.C.]

30. 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.]

31. 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.].

32. 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 BACT permit 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 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]

33. 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 March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. COOLING TOWER (EU 016)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
016	One 26-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 26-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 304,000 gpm; design hot/cold water temperatures of 92 °F/76 °F; a design air flow rate of 1,350,000 actual cubic feet per minute (acfm) per cell; a liquid-to-air flow ratio of 1.13; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application and Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}.

C. PROCESS HEATERS (EU 017)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
017	Two gas-fueled 10 MMBtu/hr process heaters

NSPS APPLICABILITY

1. 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 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].

EMISSIONS STANDARDS

2. Natural Gas Fired Process Heaters BACT Emissions Limits:

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

3. Natural Gas Fired Process Heaters 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 of the combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

   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 {Notes: The method shall be based on a continuous sampling train.}

EQUIPMENT SPECIFICATIONS

4. 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 CTs.
   [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

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

NOTIFICATION, REPORTING AND RECORDS

6. Notification: Initial notification is required for the two small gas-fueled 10 MMBtu/hr process heaters.
   [40 CFR 60.7]

7. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

D. EMERGENCY GENERATORS (018)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
018	Two model year 2007 nominal 2,250 kilowatts (kw) Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines

NESHAPS APPLICABILITY

1. 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.

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. 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.

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

EQUIPMENT SPECIFICATIONS

3. 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.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per each generator. The generators are allowed to burn ultralow sulfur diesel fuel oil (0.0015% sulfur). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

5. Emergency Generators BACT Emissions Limits:

NO_X	CO	Hydrocarbons[1]	SO_2	PM/PM_{10}
6.9 gm/bhp-hr	8.5 gm/bhp-hr	1.0 gm/bhp-hr	0.0015% ULSD FO	0.4 gm/bhp-hr

   Note 1. Hydrocarbons are surrogate for VOC.

   {The BACT limits are equal to the values corresponding to the Table 1 values cited in 40 CFR 60, Subpart IIII}

6. Emergency Generators 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 of the combined cycle unit. As an alternative, an EPA Certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values and the use of ULSD fuel oil can be used to fulfill this requirement.
   [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4211]

7. 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 {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

8. Notifications: Permittee shall submit initial notification as required by 40 CFR 60.7, 40 CFR 63.9, and 40 CFR 63.6590 (b) (i) for the two 2,250 kW RICE units.

9. Reporting: The permittee shall maintain records of the amount of liquid fuel used. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3) F.A.C.].

SECTION IV. APPENDICES

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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.

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§ 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.

DRAFT BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	CTG	8.0	42.0	8.0, 24-hr 6, 12-month [h]
	Gas	CTG & DB	7.6	52.5	
		CTG Normal Mode	4.1	23.2	
NO_X [b]	Oil	CTG	8.0	82.4	8.0, 24-hr
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr and 15, 4-hr
		CTG Normal Mode	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur FO		
VOC [e]	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
		CTG Normal Mode	1.2	4.1	
NH_3 [f]	Oil/Gas	CTG, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, FO, and basic DB mode. The stacks test limits apply only at high load (90-100% of the CTG capacity).

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for 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 NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the CTG and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. 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. The limits apply only at high load (90-100% of the CTG capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

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

h. The 4-hr, 15 ppmvd NO_X limitation is from Subpart KKKK and is in addition to the 2 ppmvd NO_X BACT limits.

NSPS FOR SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

Two natural gas heaters (EU 017) are required for the project. The purpose of these units is to heat natural gas above dew point temperature and prevent condensation. According to an interpretive memorandum by EPA in response to a Department inquiry, gas heaters in the subject size category are subject to 40 CFR 60, Subpart Dc–Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The two natural gas heaters are subject to all applicable provisions of Subpart Dc.

The provisions of Subpart Dc may be provided in full upon request and are also available beginning at Section 60.40c at: www.access.gpo.gov/nara/cfr/waisidx_07/40cfr60_07.html .

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 (X);
    b. Determination of Prevention of Significant Deterioration (X);
    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 Emissions Unit No. 018. They 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 beginning at Section 60.4200 at:

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

NSPS SUBPART KKKK REQUIREMENTS FOR GAS TURBINES

Combined Cycle Unit 3 is regulated as Emissions Units 013, 014 and 015. The gas turbines and the HRSG duct burners are part of the combined cycle unit. These emissions units shall comply with all applicable requirements of this Subpart.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

On July 6, 2006, EPA published the final NSPS Subpart KKKK (of 40 CFR 60) provisions for combustion turbines in the Federal Register. Subpart KKKK was adopted within Rule 62-204.800(8), F.A.C. Table 1 is a listing of the key NO_X limits from Subpart KKKK that apply to the West County Unit 3 project. The full provisions may be provided in full upon request and are also available beginning at Section 60.4300 at www.access.gpo.gov/nara/cfr/waisidx_07/40cfr60_07.html .

Table 1 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 (HHV)	NO_X emission standard
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2or 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_2or 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 WCEC Unit 3 project.

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 March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

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: ____

NESHAP REQUIREMENTS FOR COMBUSTION TURBINES

The WCEC Unit 3 combustion turbines are subject to all applicable requirements of 40 CFR 63, Subpart YYYY--National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The provisions of this Subpart may be provided in full upon request and are also available beginning at Section 63.6080 at:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr63c_07.html .

Following is important information related to the present status of the mentioned subpart.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as the one proposed for the Unit 4 Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

SECTION IV. APPENDIX ZZZZ

NESHAPS REQUIREMENTS-STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

The two nominal 2,250 kilowatts emergency generators are regulated as one Unit for purposes of the ARMS or Emissions Unit No. 018. These two 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:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr63d_07.html .

Harvey, Mary

From: Harvey, Mary

Sent: Friday, April 25, 2008 10:47 AM

To: 'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'

Cc: Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria

Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Attachments: COVER396.pdf; DAPPEND396.pdf; DPERMIT396.pdf; PNOTICE396.pdf; TECH396.pdf; WNOTICE396.pdf

Tracking:

Recipient	Delivery	Read
'randall_labauve@fpl.com'		
'forney.kathleen@epa.gov'		
'dee_morse@nps.gov'		
'kkosky@golder.com'		
Hoefert, Lee	Delivered: 4/25/2008 10:47 AM	Read: 4/25/2008 10:49 AM
Halpin, Mike	Delivered: 4/25/2008 10:47 AM	Read: 4/25/2008 10:50 AM
'barbara_p_linkiewicz@fpl.com'		
'paul.darst@dca.state.fl.us'		
'james.stormer@doh.state.fl.us'		
'agreene@co.palm-beach.fl.us'		
'dlodwick@royalpalmbeach.com'		
'twenham@ci.wellington.fl.us'		
'clerk@loxahatcheegroves.org'		
'davis.scottr@epa.gov'		
'sandra_silva@fws.gov'		
'NanJ58@aol.com'		
'daniellarson@earthlink.net'		
'GremlinLtd@aol.com'		
'Barryboca@aol.com'		
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Linero, Alvaro	Delivered: 4/25/2008 10:47 AM	Read: 4/25/2008 10:55 AM
Read, David	Delivered: 4/25/2008 10:47 AM	
Walker, Elizabeth (AIR)	Delivered: 4/25/2008 10:47 AM	Read: 4/25/2008 10:54 AM
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Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send".

Harvey, Mary

From: Hoefert, Lee
Sent: Friday, April 25, 2008 10:49 AM
To: Harvey, Mary
Cc: Neginsky, Raisa
Subject: RE: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Lee C. Hoefert, P.E.
Air Program Administrator
Florida Department of Environmental Protection
Southeast District
400 N. Congress Ave., Suite 200
West Palm Beach, FL 33401
561-681-6626(Phone), 561-681-6790(Fax)

From: Harvey, Mary
Sent: Friday, April 25, 2008 10:47 AM
To: 'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
Cc: Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The 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. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Harvey, Mary

From: Halpin, Mike
To: Harvey, Mary
Sent: Friday, April 25, 2008 10:50 AM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To:	'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
Cc:	Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Sent:	4/25/2008 10:47 AM

was read on 4/25/2008 10:50 AM.

Harvey, Mary

From: Read, David
To: Harvey, Mary
Sent: Friday, April 25, 2008 10:49 AM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To:	'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
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To: Harvey, Mary
Sent: Friday, April 25, 2008 10:55 AM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

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From: Linero, Alvaro
To: Harvey, Mary
Sent: Friday, April 25, 2008 10:50 AM
Subject: Read: FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To:	Linero, Alvaro
Subject:	FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Sent:	4/25/2008 10:50 AM

was read on 4/25/2008 10:50 AM.

Harvey, Mary

From: Gibson, Victoria
To: Harvey, Mary
Sent: Friday, April 25, 2008 10:49 AM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To:	'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
Cc:	Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Sent:	4/25/2008 10:47 AM

was read on 4/25/2008 10:49 AM.

Harvey, Mary

From: Hoefert, Lee
To: Harvey, Mary
Sent: Friday, April 25, 2008 10:49 AM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To:	'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
Cc:	Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Sent:	4/25/2008 10:47 AM

was read on 4/25/2008 10:49 AM.

Harvey, Mary

From: Town Clerk Loxahatchee Groves [clerk@loxahatcheegroves.org]
Sent: Friday, April 25, 2008 11:16 AM
To: Harvey, Mary
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Attachments: Read_ Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396).txt

Harvey, Mary

From: Sandra_V_Silva@fws.gov
Sent: Friday, April 25, 2008 12:20 PM
To: Harvey, Mary
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Return Receipt

Your document:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
was received by:	Sandra V Silva/R9/FWS/DOI
at:	04/25/2008 10:19:54 AM

Harvey, Mary

From: Barbara_P_Linkiewicz@fpl.com
Sent: Friday, April 25, 2008 12:05 PM
To: Harvey, Mary
Subject: Barbara P Linkiewicz/GC/FPL is out of the office.

I will be out of the office starting 04/25/2008 and will not return until 05/06/2008.

I will out of town and unavailable. Pls contact Matt Raffenberg at 561 691 2808 or Jackie Lorne at 561 691 7063 in my absence.

Harvey, Mary

From: J. William Louda [blouda@fau.edu]
Sent: Friday, April 25, 2008 1:02 PM
To: Harvey, Mary
Subject: RE: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Got it.

Dr. J. William Louda, Senior Scientist
Department of Chemistry and Biochemistry
and The Environmental Sciences Program
Florida Atlantic University
777 Glades Road
Boca Raton, FL 33431 USA
(561) 297-3309 FAX (561) 297-2759
blouda@fau.edu

"The saddest aspect of life right now is that science gathers knowledge faster than society gathers wisdom." (Isaac Asimov)

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, April 25, 2008 10:47 AM
To: randall_labauve@fpl.com; forney.kathleen@epa.gov; dee_morse@nps.gov; kkosky@golder.com; Hoefert, Lee; Halpin, Mike; barbara_p_linkiewicz@fpl.com; paul.darst@dca.state.fl.us; james.stormer@doh.state.fl.us; agreene@co.palm-beach.fl.us; dlodwick@royalpalmbeach.com; twenham@ci.wellington.fl.us; clerk@loxahatcheegroves.org; davis.scottr@epa.gov; sandra_silva@fws.gov; NanJ58@aol.com; daniellarson@earthlink.net; GremlinLtd@aol.com; Barryboca@aol.com; blouda@fau.edu; pbcenvirocoalition@gmail.com
Cc: Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

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http://www.adobe.com/products/acrobat/readstep.html.

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

Harvey, Mary

From: Barbara.Lenczewski@dca.state.fl.us
Sent: Friday, April 25, 2008 2:19 PM
To: Harvey, Mary
Subject: FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Return Receipt

Your document:	FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
was received by:	Barbara Lenczewski/DCA/FLEOC
at:	04/25/2008 02:20:32 PM

Harvey, Mary

From: Barbara.Lenczewski@dca.state.fl.us
Sent: Friday, April 25, 2008 2:18 PM
To: Harvey, Mary
Subject: FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Return Receipt

Your document:	FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
was received by:	Barbara Lenczewski/DCA/FLEOC
at:	04/25/2008 02:20:01 PM

Harvey, Mary

From: Walker, Elizabeth (AIR)
To: Harvey, Mary
Sent: Friday, April 25, 2008 10:54 AM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To:	'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
Cc:	Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Sent:	4/25/2008 10:47 AM

was read on 4/25/2008 10:54 AM.

Harvey, Mary

From: J. William Louda [blouda@fau.edu]
Sent: Friday, April 25, 2008 12:57 PM
To: Harvey, Mary
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Attachments: Read_ Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396).txt

Harvey, Mary

From: Barbara.Lenczewski@dca.state.fl.us
Sent: Friday, April 25, 2008 2:23 PM
To: Harvey, Mary
Subject: Re: FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Attachments: COVER396.pdf; DAPPEND396.pdf; DPERMIT396.pdf; PNOTICE396.pdf; TECH396.pdf; WNOTICE396.pdf

Barbara Lenczewski, Ph.D, AICP
State Planning Initiatives Administrator
Rural and Natural Resource Planning Section
Office of State Planning, Dept. of Community Affairs
2555 Shumard Oak Blvd.
Tallahassee, FL 32399-2100
Ph (850) 922-1786 Cell (850) 766-5776
Email: Barbara.Lenczewski@dca.state.fl.us

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

04/25/2008 02:20 PM

To <barbara.lenczewski@dca.state.fl.us>
cc
Subject FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

From: Harvey, Mary
Sent: Friday, April 25, 2008 1:17 PM
To: Skinner, Karen
Subject: FW: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

From: Harvey, Mary
Sent: Friday, April 25, 2008 10:47 AM
To: 'randall_labauve@fpl.com'; 'forney.kathleen@epa.gov'; 'dee_morse@nps.gov'; 'kkosky@golder.com'; Hoefert, Lee; Halpin, Mike; 'barbara_p_linkiewicz@fpl.com'; 'paul.darst@dca.state.fl.us'; 'james.stormer@doh.state.fl.us'; 'agreene@co.palm-beach.fl.us'; 'dlodwick@royalpalmbeach.com'; 'twenham@ci.wellington.fl.us'; 'clerk@loxahatcheegroves.org'; 'davis.scottr@epa.gov'; 'sandra_silva@fws.gov'; 'NanJ58@aol.com'; 'daniellarson@earthlink.net'; 'GremlinLtd@aol.com'; 'Barryboca@aol.com'; 'blouda@fau.edu'; 'pbcenvirocoalition@gmail.com'
Cc: Linero, Alvaro; Read, David; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

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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. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,
DEP, Bureau of Air Regulation

Harvey, Mary

From: Dee_Morse@nps.gov
Sent: Monday, April 28, 2008 6:10 PM
To: Harvey, Mary
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Return Receipt

Your document:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
was received by:	Dee Morse/DENVER/NPS
at:	04/28/2008 04:09:56 PM MDT

Harvey, Mary

From: Diane DiSanto [Ddisanto@RoyalPalmBeach.com]
To: undisclosed-recipients
Sent: Friday, April 25, 2008 3:24 PM
Subject: Read: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Your message

To: Ddisanto@RoyalPalmBeach.com
Subject:

was read on 4/25/2008 3:24 PM.

Harvey, Mary

From: Randall_R_LaBauve@fpl.com
Sent: Friday, April 25, 2008 11:07 AM
To: Harvey, Mary
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

Return Receipt

Your document:	Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
was received by:	Randall R LaBauve/GC/FPL
at:	04/25/2008 11:06:45 AM

Harvey, Mary

From: Randall_R_LaBauve@fpl.com
Sent: Friday, April 25, 2008 11:10 AM
To: Harvey, Mary
Subject: Re: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)
Attachments: COVER396.pdf; DAPPEND396.pdf; DPERMIT396.pdf; PNOTICE396.pdf; TECH396.pdf; WNOTICE396.pdf

Received
"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

04/25/2008 10:46 AM

To: randall_labauve@fpl.com, forney.kathleen@epa.gov, dee_morse@nps.gov, kkosky@golder.com, "Hoefert, Lee" <Lee.Hoefert@dep.state.fl.us>, "Halpin, Mike" <Mike.Halpin@dep.state.fl.us>, barbara_p_linkiewicz@fpl.com, paul.darst@dca.state.fl.us, james.stormer@doh.state.fl.us, agreene@co.palm-beach.fl.us, dlodwick@royalpalmbeach.com, twenham@ci.wellington.fl.us, clerk@loxahatcheegroves.org, davis.scottr@epa.gov, sandra_silva@fws.gov, NanJ58@aol.com, daniellarson@earthlink.net, GremlinLtd@aol.com, Barryboca@aol.com, blouda@fau.edu, pbcenvirocoalition@gmail.com
cc: "Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>, "Read, David" <David.Read@dep.state.fl.us>, "Walker, Elizabeth (AIR)" <Elizabeth.Walker@dep.state.fl.us>, "Gibson, Victoria" <Victoria.Gibson@dep.state.fl.us>
Subject: Florida Power & Light Company - DEP File #0990646-002-AC (PSD-FL-396)

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