Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 30, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

John M. Lindsay, Plant General Manager
Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Re: Project No. 0850001-010-AC
Air Permit No. PSD-FL-327
FPL Martin Power Plant
New 1150 MW Combined Cycle Unit 8

Dear Mr. Lindsay:

Florid Power and Light applied for a PSD air permit to construct an 1150 MW "4-on-1" combined cycle gas turbine unit at the existing FPL Martin Power Plant. Enclosed for this project is the Department's Intent to Issue Permit package, which includes the following: "Intent to Issue Air Construction Permit", "Public Notice of Intent to Issue Air Construction Permit", "Technical Evaluation and Preliminary Determination (draft BACT determinations), and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Al Linero, Manager of the New Source Review Section, at the above letterhead address. If you have any questions, please call Mr. Jeff Koerner at 850/921-9536 or Mr. Linero at 850/921-9523.

Sincerely,

CH Fancy

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. John M. Lindsay
Plant General Manager
Florida Power & Light Company
Martin Power Plant
P.O. Box 176
Indiantown, FL 34956

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 7-12-02

C. Signature
X Charles Maloy ☒ Agent ☐ Addressee

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

Charles Maloy

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

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Numb 7001 0320 0001 3692 8376

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7001 0320 0001 3692 8376

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

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Sent To
John M. Lindsay
Street, Apt. No.; or PO Box No.
PO Box 176
City, State, ZIP+4
Indiantown, FL 34956

PS Form 3800, January 2001 See Reverse for Instructions

In the Matter of an
Application for Permit by:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
Mr. John M. Lindsay, Plant General Manager

Project No. 0850001-010-AC
Draft Air Permit No. PSD-FL-327
FPL Martin Power Plant
New Combined Cycle Unit 8

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Florida Power and Light (FPL), applied on February 1, 2002 to the Department for a PSD permit for a 1150 MW combined cycle gas turbine project (Unit 8) at the FPL Martin Power Plant located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212 and Code of Federal Regulations, 40 CFR 52.21. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed <u>Public Notice of Intent to Issue PSD Permit</u>. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed <u>Public Notice</u>. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (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; and (g) A statement of the relief sought by the petitioner, stating precisely the action 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 Department'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.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/31/02 to the persons listed:

Mr. John M. Lindsay, FPL*
Mr. K. H. Simmons, FPL
Mr. Willie Welch, FPL
Mr. Ken Kosky, Golder Associates Inc.
Mr. Tom Tittle, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Mr. Buck Oven, DEP Siting

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.

Victoria Gibson July 31, 2002
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. PSD-FL-327

FPL Martin Power Plant, New Combined Cycle Unit 8
Martin County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power and Light Company. The permit is one of several authorizations needed to construct a nominal 1150 MW combined cycle gas project at the FPL Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida. In accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21, Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. John M. Lindsay, Plant General Manager. The applicant's address is FPL Martin Power Plant, P.O. Box 176, Indiantown, FL 34956.

The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. The gas turbines will be fired primarily with natural gas and up to 500 hours per year of very low sulfur distillate oil as a restricted alternate fuel. For the first year of operation, each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

During simple cycle operation and gas firing, NOx emissions will be controlled by dry low-NOx combustion technology. During simple cycle operation and oil firing, NOx emissions will be controlled by wet injection techniques. During the predominant combined cycle operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. To meet peak power demands, the following alternate methods of operation will be authorized: high-temperature peaking (60 hours/year for simple cycle and 400 hours/year for combined cycle operation); steam injection for power augmentation (400 hours/year); and duct burning (2880 hours/year). During these restricted alternate methods of operation, NOx emissions are slightly higher. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. The Department determines that these control techniques and equipment represent the Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C. and 40 CFR 52.21. Emissions standards are presented in the draft permit on file with the Department.

Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines, the gas fired-fuel heaters, and the cooling tower that comprise new Unit 8 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	826	100	Yes
Pb	0.025	0.6	No
NOx	683	40	Yes
PM/PM_{10}	322/275	15/25	Yes
SO_2	280	40	Yes
SAM	30	7	Yes
VOC	110	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour SO_2 impacts Therefore, multi-

Notice for Newspaper

source modeling was only required for the 24-hour SO_2 impacts. The predicted impacts in the Everglades National Park are less than the applicable PSD Class I significant impact levels except for the 24-hour SO_2 impacts; therefore, multi-source Class I PSD increment modeling was only required for the 24-hour SO_2 impacts. The following table summarizes the maximum predicted PSD Class I and II 24-hour SO_2 increment consumed by the new project and by all increment-consuming sources.

Area and Averaging Time	Increment Consumed Project/All Sources (SO_2, ug/m^3)	Allowable Increment All Sources (SO_2, ug/m^3)	Increment Consumed Project/All Sources (Percent)
Class I, 24-hour (Everglades National Park)	0.4/3.5	5	8/70
Class II, 24-hour (Vicinity of Plant)	9/41	91	10/45

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. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (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; and (g) A statement of the relief sought by the petitioner, stating precisely the action 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
(Mailing Address: 2600 Blair Stone Road, MS #5505)
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
(Mailing Address: P.O. Box 15425)
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

Notice for Newspaper

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION
(DRAFT BACT DETERMINATIONS)

PROJECT

FPL Martin Power Plant
Unit 8 Combined Cycle Project

Project No. 0850001-010-AC
Draft Permit No. PSD-FL-327

COUNTY

Martin County

APPLICANT

Florida Power and Light
P.O. Box 176
Indiantown, FL 34956

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

July 30, 2002

Filename: 327 TEPD.doc

TABLE OF CONTENTS

This document describes the overall project, identifies applicable air pollution regulations, provides the rationale for draft determinations of the Best Available Control Technology, establishes emissions standards, presents a review of the air quality impact analysis, and makes a preliminary determination to issue the air permit. It is organized by the following sections.

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

Processing Schedule

- Received application on February 1, 2002;
- Additional information requested on March 1, 2002;
- Received additional information on May 6, 2002; application deemed complete.

Facility Description and Location

Florida Power and Light (FPL) operates the Martin Power Plant, which is located approximately 7 miles north of Indiantown on State Road 710 and east of Lake Okeechobee in Martin County, Florida. The existing plant currently has a total electrical generating capacity of approximately 3066 MW. Units 1 and 2 are fossil fuel-fired steam electric generators with a capacity of 863 MW each. Units 3A, 3B, 4A, and 4B are combined cycle units consisting of 170 MW gas turbines matched with heat recovery steam generators (HRSGs). Each pair of gas turbines (3A/3B and 4A/4B) provides steam to a common steam-electrical turbine (160 MW each). Units 8A and 8B are 170 MW simple cycle gas turbines.

Regulatory Categories

Title III: The facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a case-by-case 112(g) determination of the Maximum Available Control Technology (MACT).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is a steam electrical generating plant. The project will result in more than 75 MW of steam-generated electrical power and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a "4-on-1" combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment.

Gas Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, and a gas-fired heat recovery steam generator (HRSG). The project utilizes two existing 170 MW gas turbines (Units 8A and 8B) that are currently permitted for simple cycle only operation. The project adds two new 170 MW gas turbines (8C and 8D).

Fuels: Each gas turbine will fire natural gas as the primary fuel and distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 500 hours per year per gas turbine (or equivalent) for oil firing.

Generating Capacity: Each of the four gas turbines has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Each of the four heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4-on-1" combined cycle unit is 1150 MW.

Controls: CO, PM/PM_{10}, 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 restricting the amounts of very low sulfur distillate oil. NOx emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NOx controls, a selective catalytic reduction (SCR) system further reduces NOx emissions during combined cycle operation.

Continuous Monitors: Each gas turbine is required to continuously monitor NOx emissions in accordance with the acid rain provisions. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

Stack Parameters: Each gas turbine has a simple cycle (or bypass) stack that is 80 feet tall and 22.0 feet in diameter. Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is 120 feet tall and 19.0 feet in diameter. The following summarizes the exhaust characteristics:

			Simple Cycle Operation		Combined Cycle Operation	
Fuel	Heat Input Rate	Compressor Inlet Temp.	Exhaust Temp.	Flow Rate ACFM	Exhaust Temp., °F	Flow Rate ACFM
Gas	1600 MMBtu/hour	59° F	1116° F	2,389,500	202° F	1,004,200
Oil	1811 MMBtu/hour	59° F	1098° F	2,735,300	295° F	1,193,900

Operating Modes: Each gas turbine may operate in simple cycle mode (without the HRSG) to produce only shaft-driven electrical power with hot exhaust through the bypass stack. This mode is typically reserved for meeting peak energy demand periods because it is much less efficient. Operation in combined cycle mode recovers heat energy from the HRSG in the form of steam, which is delivered to the steam-electrical turbine to produce steam-generated electrical power. For the first year of operation, the applicant requests 3390 hours per year per gas turbine of simple cycle operation until the combined cycle unit is complete. Once combined cycle operation is established, the applicant requests an average of 1000 hours per year for the combination of four gas turbines. The applicant has also requested the following additional modes of operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in shaft-driven electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging may occur during simple or combined cycle operation and no restrictions are requested. Fogging will be implemented at ambient temperatures of 60° F or higher.
- Duct Burning: During combined cycle operation, duct burners in the HRSG may be fired with natural gas to raise the useful heat energy of the gas turbine exhaust and produce additional steam-generated electricity. Although the overall cycle of the unit is less efficient in this mode, duct firing is useful during periods of high-energy demand. Duct firing may result in increased mass emissions rates due to the increased fuel consumption. The applicant requests 2880 hours of duct burning per year for each gas unit.
- Power Augmentation: Power augmentation is the injection of steam into the gas turbine compressor, which results in a higher mass flow rate through the gas turbine and provides a slight increase in shaft-driven electrical power production. Power augmentation is used at loads above 95% of base load and may be used alone or in combination with duct burning. Steam injection may cause some increase in emissions of carbon monoxide. The applicant requests 400 hours per year per gas turbine of power augmentation.
- Peaking: Peaking allows gas turbine temperatures to drift higher than normal and results in increased in shaft-driven electrical power production. Peaking is expected to increase NOx emissions from the gas turbine due to higher temperatures. During combined cycle operation, NOx emissions would be reduced to allowable levels with SCR. For each gas turbine, the applicant requests operation in the peaking mode up to 60 hours per year for simple cycle operation and 400 hours per year for combined cycle operation.

The restrictions identified above are included as limitations in the draft permit.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, gas-fired fuel heaters, and cooling tower).

Table 2-1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions, TPY		Maximum, TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
	1st Year	2nd Year			
CO	228	826	826	100	Yes
Pb	0.025	0.025	0.025	0.6	No
NOx	664	683	683	40	Yes
PM/PM_{10}	69/69	322/275	322/275	15/25	Yes
SO_2	156	280	280	40	Yes
SAM	16	30	30	7	Yes
VOC	23	110	110	40	Yes

Based on the applicant's estimates, the project requires the determinations of the Best Available Control Technology (BACT) for emissions of CO, NOx, PM/PM_{10}, SO_2, SAM, and VOC.

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 state rules and regulations of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, and 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 applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 51	Submittal of Implementation Plans – PSD
Part 52	Approval of Implementation Plans – PSD
Part 60	New Source Performance Standards (NSPS)
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

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. 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. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Project emissions exceeding these rates are considered "significant". For each significant pollutant, the applicant must employ the Best Available Control Technology (BACT) to minimize emissions and conduct an appropriate ambient impact analyses. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several significant regulated pollutants.

Note: This project is reviewed in accordance with the federally delegated PSD program because it is subject to electrical power plant site certification.

Description of PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of a PSD Significant Emission Rate. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation must be performed for each emissions unit and pollutant under consideration. BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards specified in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). When reviewing control technologies for regulated pollutants, the Department will favorably consider the control or reduction of other "non-regulated" air pollutants in determining BACT. The Department will also favorably consider control technologies that utilize pollution prevention. These approaches are consistent with EPA's consideration of environmental impacts and strategies for pollution prevention.

The second part of PSD review requires an Air Quality Analysis consisting 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 and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The applicant must satisfactorily demonstrate that potential project emissions will not significantly contribute to or cause a violation of any ambient air quality standards and will not adversely impact Class I and Class II Areas.

4. AVAILABLE INFORMATION

In addition to the information submitted by the applicant, the Department also relied on the following available information to make these determinations:

- DOE web site information on Advanced Turbine Systems Project;
- Test data for various similar projects including the City of Tallahassee's Purdom Generating Station and Gulf Power's Lansing Smith Plant;
- General Electric technical documents regarding the Model PG7241(FA) gas turbine, the DLN "hot nozzle" combustor, the gas turbine control system, and the startup/shutdown data;
- EPA's Alternative Control Techniques Document: NOx Emissions from Stationary Gas Turbines (1993);
- U. S. Department of Energy Report (11/05/99) titled, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" prepared by Onsite Sycom Energy Corporation;
- Onsite Sycom Energy Corporation's report titled "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" (1999) prepared for the U.S. Department of Energy
- AP-42, Section 3.1 for gas turbines (04/00);
- EPA memorandums regarding gas turbines and MACT applicability dated 12/30/99 and 08/21/01; and
- Recently issued permits for the General Electric Model PG7241(FA) gas turbine.

The Department also reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse. A list of recent BACT determinations regarding similar projects in Florida and the Southeastern United States is provided in See Attachment A.

5. DRAFT BACT STANDARDS – NITROGEN OXIDES

<u>Discussion of NOx Emissions</u>

A gas turbine is sometimes referred to a "heat engine". In operation, air is compressed, combusted with fuel to produce hot exhaust gases (≈ 2350° F), and expanded in the turbine section to drive a shaft to produce useful energy. The majority of the energy produced is returned to the compressor and other supporting equipment. The remainder can be used to drive an electrical generator to produce electricity. This power cycle is known as the Brayton cycle and is commonly referred to as the "simple cycle mode of operation". A heat recovery steam generator may be added to convert the remaining heat energy of the exhaust gases into steam to drive a steam-electric turbine to produce additional electricity. This additional power cycle is known as the Rankine cycle. Gas turbines with heat recovery steam generators are commonly referred to as combined cycle units.

For gas turbines, the primary pollutant of concern is nitrogen oxides (NOx) due to the high temperatures. Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule (nitrogen dioxide). NOx forms from the dissociation of molecular nitrogen and oxygen into their atomic forms and subsequent recombination into seven different oxides of nitrogen. Three primary mechanisms cause NOx emissions:

- *Thermal NOx* forms in the high temperature area of the gas turbine combustor. It increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen. Less NOx is formed during lean combustion (low fuel-to-air ratio) because the flame temperature is lower.

- *Prompt NOx* is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt NOx to overall NOx emissions is relatively small in combustors that operate near the stoichiometric air-to-fuel ratio. However, new combustors that operate in lean premix mode generate far less thermal NOx, which makes prompt NOx a greater contributor to overall NOx emissions for these types of units. Therefore, prompt NOx may provide a practical limit for NOx control by lean combustion.

- *Fuel NOx* forms from the oxidation of nitrogen in the fuel. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen (FBN).

Uncontrolled NOx emissions from gas turbines may range as high as 600 parts per million by volume, dry, corrected to 15 percent oxygen. The federal New Source Performance Standards (40 CFR 60, Subpart GG) regulate NOx emissions from large utility gas turbines to 75 ppmvd corrected to 15% oxygen and ISO conditions, which can then be adjusted for the fuel-bound nitrogen content and heat rate of the given unit.

Descriptions of Available NOx Controls

The following technologies were identified as potentially applicable for the control of NOx from gas turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd corrected to 15% oxygen.

Lean Premix (LPM) Combustor Design: Efforts over the last ten years to minimize NOx emissions from gas turbines have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. General Electric's version of the lean premix combustor design is called dry low-NOx (DLN) combustion. The following is a general description of the typical air/fuel combustion modes used to achieve lean premix combustion. In the primary mode, fuel is supplied only to the primary (diffusion) nozzle to ignite, accelerate, and operate the unit over a range of low-load to mid-load operation and up to a given combustion reference temperature. Once the first combustion reference temperature is reached, operation in a lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in a secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the lean premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. Other manufacturer's models maintain the primary diffusion nozzle, which leads to slightly higher NOx emissions.

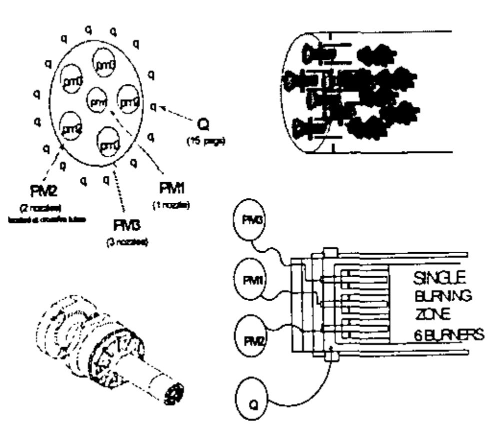


Figure 5-1. GE's DLN2.6 Combustor

Figure 5-1 represents the fuel nozzle arrangement of the General Electric DLN-2.6 can-annular combustor, which is the technology specified for proposed project. With this design, each combustor includes six nozzles within which fuel and air are fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

The full lean premix mode of operation typically occurs between 50% and 70% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for lean premix combustion, the automated gas turbine control system becomes a critical component of the overall system. Although research for oil firing continues, lean premix combustion technology is currently only effective for firing natural gas. Dual fuel combustors must also employ wet injection to reduce NOx emissions when firing oil.

General Electric currently guarantees a NOx level of 9 ppmvd corrected to 15% oxygen for the Frame 7FA series of gas turbines. This low NOx emission rate is achieved while also minimizing CO emissions below 9 ppmvd. There are numerous projects installed and currently under construction with General Electric's dry low-NOx combustion technology. The following tables presents test results for a "new and clean" 7FA gas turbine firing natural gas in combined cycle mode without add on NOx controls.

Table 5-1. Test Results for GE 7FA Gas Turbine, City of Tallahassee's Purdom Station

Percent of Full Load	NOx, ppmvd @15% O_2	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

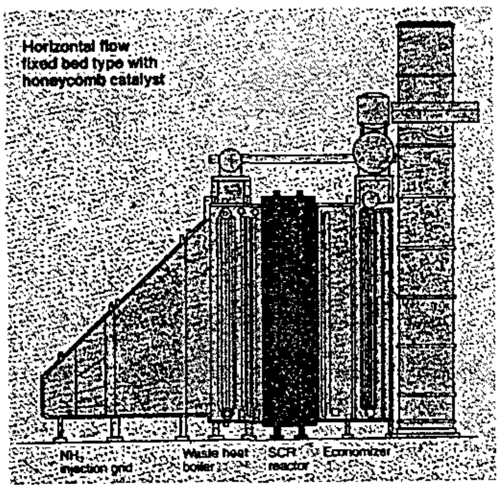
Table 5-2. Test Results for GE 7FA Gas Turbine, TECO Polk Power Station

Percent of Full Load	NOx, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

These test results confirm NOx emission levels below the manufacturer's emissions guarantee. Recent conversations with other operators indicate that the lean premix emission characteristics also extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE. Lean premix combustion technology results in control efficiencies approaching 95%.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, 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 combustion turbine. The New Source Performance Standards for gas turbines (40 CFR 60, Subpart GG) was developed around this technology in the late 1970's. Wet injection techniques are generally reserved for oil firing because advanced lean premix combustor designs can achieve much lower NOx emissions for gas firing without wet injection. However, for oil firing, the advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NOx emissions of less than 42 ppmvd when combined with wet injection techniques. Therefore, wet injection remains a viable alternative when firing oil in modern dual fuel combustors. Wet injection results in control efficiencies approaching 75% for oil firing.

Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. The figure below shows the general arrangement of the ammonia injection grid and SCR catalyst with respect to the heat recovery steam generator for a combined cycle unit. The exhaust gas temperature must be maintained between 450° F and 850° F for this reaction to proceed satisfactorily. For combined cycle gas turbines, the temperature is within the proper range and conventional catalysts such as vanadium or titanium oxide are acceptable. However, the exhaust from simple cycle gas turbines can exceed 1000° F and require more expensive high temperature zeolite catalysts and possibly additional gas cooling to protect the catalyst. Ammonia that escapes past the catalyst without reacting with NOx is called "ammonia slip". If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst. The catalyst is typically replaced every 5 to 7 years although vendors typically guarantee catalysts for about three years. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects permitted with very low NOx emissions (< 2.5/10 ppmvd for gas/oil firing). There are a few "hot SCR" systems employed on smaller simple cycle units with slightly higher NOx emissions. SCR results in control efficiencies of approaching 98%.



SCONOx™: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and is distributed through Alstom Power for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which is within the typical range of exhaust gas from heat recovery steam generator in a combined cycle gas turbine. SCONOx™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas where cost is not a factor in establishing an emissions standard. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. SCONOx™ can also achieve control efficiencies approaching 98% without the additional ammonia emissions associated with SCR.

XONON™: This is an emerging technology that partially burns fuel in a low-temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature (and less NOx formation) followed by flameless catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but the design will be unique for each manufacturer and model of gas turbine. It is anticipated that control efficiencies may approach 98%.

Selective Non-Catalytic Reduction (SNCR): This technology works on the same principle as SCR, but in the absence of a catalyst. Ammonia (or urea) is injected directly into a hot gas stream (1400° F to 2000° F), which promotes the conversion of NOx to nitrogen and water given sufficient residence time. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100° F is too low to support the NOx conversion mechanism. However, with a large duct burner in the heat recovery steam generator, it is possible to reach the exhaust gas temperatures that would make SNCR feasible.

Applicant's NOx BACT Proposal – Combined Cycle Operation

In addition to the dry low NOx (DLN) combustion technology for the specified gas turbine, the applicant identified the following add-on control technologies for reducing NOx emissions: NOxOut, Thermal DeNOx, NSCR, XONON™, wet injection, SCR, and SCONOx™ . Of these technologies, the applicant indicates that only DLN, wet injection, SCR, SCONOx™ , and XONON™ are feasible for the project. The applicant does not believe that XONON™ is yet available or demonstrated for an "F-class" gas turbine or that SCONOx™ has been demonstrated for such a unit. The applicant did review SCONOx™ as the top control technology, followed by SCR. These add-on controls would be in addition to DLN combustion for gas firing and wet injection for oil firing. The applicant noted the following adverse impacts with regard to SCONOx™ .

Energy Impacts: The pressure drop across the SCONOx™ system causes backpressure on the gas turbine, which can reduce power output. SCONOx™ also requires the use of natural gas and steam to regenerate the catalyst. The overall energy requirement is approximately equivalent to 34,800,00 kWh per year for each unit. The combined energy requirements in terms of natural gas usage would be 362 million cubic feet of natural gas per year, which is roughly 2.3% of the gas turbine heat input. The applicant believes that this is approximately 7 times that of SCR.

Environmental Impacts: Due to the backpressure and energy requirements for SCONOx™ noted above, the applicant estimates that such a system would increase criteria pollutants by 41 tons per year and carbon dioxide emissions by 23,000 tons per year for each gas turbine.

Economic Impacts: The applicant estimates that the installation of SCONOx™ to achieve a NOx standard of 2.5 ppmvd corrected to 15% oxygen for gas firing would result in estimated annualized costs of $5,682,000 per year and an overall cost effectiveness of $18,900 per ton of NOx removed. This compares to the applicant's estimated cost effectiveness of $4900 per tons of NOx removed for an SCR system at 2.5 ppmvd corrected to 15% oxygen.

The applicant rejects SCONOx™ based on the significant energy, environmental, and economic impacts. SCONOx™ and SCR are capable of achieving nearly the same level of NOx reduction. Although SCONOx™ achieves this level without additional emissions of ammonia, SCR systems can be designed and operated to minimize ammonia slip. The use of distillate oil for this project further complicates the SCONOx™ system and can cause premature fouling. It is possible that a SCOSOx™ catalyst could be added to reduce SO_2 emissions. The applicant believes that the energy and environmental disadvantages of a SCONOx™ system outweigh the any potential additional reductions in NOx. The applicant requests the following NOx standards as BACT for combined cycle operation.

a. Oil Firing: 12 ppmvd @ 15% O_2, 24-hour average

b. Gas Firing: 2.5 ppmvd @ 15% O_2, 24-hour average

{Note: These limits represent approximately a 70% reduction from gas firing with DLN combustion (9 ppmvd @ 15% O_2) and oil firing with wet injection (42 ppmvd @ 15% O_2).}

Department's Draft BACT Determinations – Combined Cycle Operation

The Department also ranks SCONOx™ and SCR as the top add-on control technologies for combined cycle operation. SCONOx™ has been demonstrated on small units in California and has been purchased for a small source in Massachusetts. California regulators and have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx™. The overall project includes several more 250 MW blocks with SCR for control. According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two "F" class units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, EPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with a SCONOx™ system. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently due to cost considerations. The Department is interested in seeing this ammonia-free emissions technology demonstrated on a large "F" class unit. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- The pressure drop across the SCONOx™ system may be greater than that of SCR.

- The energy losses described are relatively small and would occur on a day-to-day basis. The applicant's estimates of additional emissions assumes that the replacement energy would be needed each and every day, 24 hours a day.
- The Department does not endorse the applicant's estimate of the cost effectiveness for either SCONOx™ or SCR. However, the estimates appear to at the high end of the range of estimates for other similar projects. It is unlikely that SCONOx™ would be cost effective at even half of the estimated cost.

The Department rejects SCONOx™ primarily as not being cost effective and accepts conventional SCR as the Best Available Control Technology. The Department establishes the following draft BACT standards for combined cycle operation.

a. Oil Firing: 10 ppmvd @ 15% O_2, 24-hour average

b. Gas Firing: 2.5 ppmvd @ 15% O_2, 24-hour average

These determinations are consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. The above standards include any emissions resulting from duct burning. In at least four previous BACT determinations, the Department specified NOx BACT of 10 ppmvd @ 15% O_2 for Frame 7 combined cycle gas turbines with conventional SCR. Compliance with the standards will be demonstrated by continuous emissions monitoring system (CEMS). The Department also notes that other similar combined cycle projects in Maine and Washington received BACT limits of 2.0 ppmvd @ 15% O_2 for gas firing with SCR. However, the Department's proposed BACT limit considers measurement uncertainties associated with very low emission rates and the proposed ammonia slip limit of 5 ppmvd @ 15% O_2. EPA Region 4 has commented that 2.5 ppmvd @ 15% O_2 represents the lowest BACT level in the region and that the 24-hour averaging period is acceptable in light of the low standard. The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines.

<u>Applicant's NOx BACT Proposal – Simple Cycle Operation</u>

The applicant notes that the project is intended to be a base loaded 4-on-1 combined cycle unit. The ability to operate in simple cycle mode is desired to meet peak demands during the construction of the combined cycle units (up to 3390 hours per year per gas turbine). Simple cycle mode is also requested as a backup mode once the combined cycle project is complete (up to an average of 1000 hours per year per gas turbine). Due to the high exhaust temperatures of simple cycle operation, SCONOx™ is not technically feasible. The applicant does not believe that SCR using high temperature catalysts ("hot" SCR) is technically feasible or demonstrated for large "F-class" gas turbines. Noted is a determination by the Maryland Department of Environment that hot SCR was not LAER due to technical feasibility issues and collateral environmental impacts. EPA Region III concurred with the Maryland determination. However, the applicant reviewed hot SCR as the top control for simple cycle operation and noted the following adverse impacts from this technology.

Energy Impacts: The pressure drop across the hot SCR system will cause backpressure on the gas turbine, which can reduce power output by up to 0.5%. At 3390 hours per year, the lost energy is equivalent to about 320 residential customers per year or, in terms of natural gas usage, would be 37 million cubic feet of natural gas per year.

Environmental Impacts: The applicant comments that lost power due to backpressure would likely be replaced by older less efficient units with higher emissions. Due to the very low predicted ambient impacts from DLN combustion alone, the applicant does not believe that hot SCR would only have marginal overall air quality benefits given the proposed period of long-term operation (1000 hours per year per gas turbine).

Economic Impacts: The applicant estimates that the installation of hot SCR to achieve a NOx standard of 3.5/15 ppmvd corrected to 15% oxygen for gas/oil firing would result in estimated annualized costs of $1,728,800 per year and an overall cost effectiveness of $25,200 per ton of NOx removed assuming 3390 hours per year of operation. Assuming 1000 hours per year of operation increases the estimated cost effectiveness to $57,700.

The applicant rejects hot SCR based on the adverse energy, environmental, and economic impacts. The applicant considers hot SCR to be technically infeasible for the project because it has not yet been demonstrated on an "F" class dual fuel gas turbine. The applicant requests the following NOx standards as BACT for simple cycle operation.

a. Oil Firing: 42 ppmvd @ 15% O_2, 24-hour average
b. Gas Firing: 9.0 ppmvd @ 15% O_2, 24-hour average
c. Gas Firing w/Power Augmentation or Peaking: 15.0 ppmvd @ 15% O_2, 24-hour average

Department's Draft NOx BACT Determinations – Simple Cycle Operation

The Department also ranks hot SCR as the top add-on control technology. The catalyst will cause a small drop in pressure, which can reduce power output. Examples of this technology is the Carson Plant in Sacramento, California (GE LM6000-PA, < 50 MW) and the proposed new unit for the Sacramento Municipal Utilities District (GE 7EA, 75MW), which were determinations of the Lowest Achievable Emission rate (LAER) for a nonattainment area. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- It is noted that ambient impacts are reviewed separately from the determination of BACT controls.
- Although the Department does not endorse the applicant's estimate of the cost effectiveness for hot SCR, it does believe that this technology is not cost effective for the limited operation expected.

The Department rejects hot SCR primarily based on costs and accepts dry low-NOx combustion for gas firing and wet injection for oil firing as the Best Available Control Technology during simple cycle operation. The Department establishes the following draft BACT standards.

a. Oil Firing: 42 ppmvd @ 15% O_2, 3-hour average
b. Gas Firing: 9.0 ppmvd @ 15% O_2, 24-hour average
c. Gas Firing w/Power Augmentation: 12.0 ppmvd @ 15% O_2, 1-hour average
d. Gas Firing w/Peaking: 15.0 ppmvd @ 15% O_2, 1-hour average

This determination is consistent with recent determinations for simple cycle gas turbine projects in attainment areas. Power augmentation and peaking were separated because of different NOx emissions levels. 1-hour standards were defined because these modes of operation are typically short and no add-on controls are in place. Compliance with the standards will be demonstrated by continuous emissions monitoring system (CEMS). The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines.

6. DRAFT BACT STANDARDS – CARBON MONOXIDE

Discussion of CO Emissions

Gas turbines emit carbon monoxide (CO) due to incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. However, the dry low-NOx combustor design for General Electric's Frame 7FA gas turbine has also successfully reduced CO emissions concurrently with NOx emissions.

Applicant's CO BACT Proposal

The applicant identified two control options that are technically feasible and commercially available for gas turbines: an efficient combustion design with good operating practices and a catalytic oxidation system. After attaining lean premix steady-state operation, the dry low-NOx combustion design of the General Electric Model PG7241(FA) gas turbine results in low emissions of CO while also maintaining low NOx emissions. The Speedtronic™ automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters including, but not limited to, air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. The dry low-NOx combustion design and Speedtronic™ control system are integral to the Model PG7241(FA) gas turbine. "Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustor and control system. No adverse energy, environmental, or economic impacts were identified with the use of an efficient combustion design and good operating practices.

A catalytic oxidation system consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) at much lower temperatures (650°F to 1150°F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. Control efficiencies can approach more than 90% given a sufficient inlet concentration. A catalytic oxidation system could be installed either before the HRSG or within the HRSG. Installation within the HRSG would also reduce CO emissions from the duct burner. Capital costs and technical feasibility are not affected by placement of the HRSG.

The applicant recognized a catalytic oxidation system as the top control for CO emissions, but identified the following additional adverse impacts.

Energy Impacts: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.5 to 2 inches of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit resulting in an estimated energy penalty of approximately 3 million kWh/year. The applicant estimates the lost power generation to be approximately equivalent 31 million SCF of natural gas per year to replace the lost energy.

Environmental Impacts: The applicant contends that the maximum CO impacts are less than 0.1% of the applicable ambient air quality standard and no significant environmental benefit is realized by the installation of a catalytic oxidation system. The applicant states that the requirement of an oxidation catalyst would result 1970 tons per year more of carbon dioxide.

Economic Impacts: The applicant estimates that the installation of a catalytic oxidation system would result in total capital investment of approximately $1,644,300 for one gas turbine with a total annualized cost of approximately $691,000 per year per gas turbine. Assuming 85% control efficiency, the catalytic oxidation system would remove in an additional 165 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $4190 per ton of CO removed.

The applicant rejected the catalytic oxidation system as not cost effective for the project. In addition, the applicant did not believe the additional controls would provide any measurable reductions in air quality impacts. The applicant proposed the following CO emissions standards for project based on the efficient combustion, the firing of natural gas as the primary fuel, and good operating practices.

a. Oil Firing: 20.0 ppmvd (14.1 ppmvd @ 15% O_2)
b. Gas Firing: 9.0 ppmvd (7.4 ppmvd @ 15% O_2)
c. Gas Firing w/Power Augmentation: 15.0 ppmvd (12.0 ppmvd @ 15% O_2)
d. Gas Firing w/Duct Burning: 22.9 ppmvd (14.1 ppmvd @ 15% O_2)
e. Gas Firing w/Power Augmentation and Duct Burning: 29.5 ppmvd (19.2 ppmvd @ 15% O_2)

The applicant requests that compliance with the proposed standards should be based on the average of three test runs conducted in accordance with EPA Method 10.

Department's Draft CO BACT Determinations

The Department also recognizes the catalytic oxidation system as the top control alternative for CO emissions. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- The Department agrees that installation of a catalytic oxidation system would result in a small energy penalty due to the pressure drop across the catalyst.

- The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. The PSD preconstruction review process is specifically established for areas that are meeting the ambient air quality standards in order to prevent the deterioration of the current air quality. Actual ambient impacts from the project are evaluated in the modeling analysis and are not considered in making a determination of the Best Available Control Technology. A catalytic oxidation system would also reduce emissions of volatile organic compounds.
- The Department does not endorse the applicant's estimate of the cost effectiveness of $4165/ton of CO removed for a catalytic oxidation system. Recent similar projects (for example, CPV Gulfcoast) have obtained vendor equipment cost quotes that are approximately 25% less. However, the estimate appears to be within the high end of the range of such estimates for other similar projects ($1500 to 4500 per ton).

Recent performance tests for the same model gas turbine indicate actual CO emission levels of less than 1 ppmvd @ 15% O_2 when firing natural gas and less than 2 ppmvd @ 15% O_2 when firing distillate oil (for example, City of Tallahassee's Purdom Generating Station, TECO's Polk Power Station and FPL's Martin Plant). As shown below, recent performance tests for the same model gas turbine at the Gulf Power's Lansing Smith Plant indicate very low CO emissions when injecting steam for power augmentation and duct burning.

Table 6-1. GE Frame 7FA Gas Turbine w/275 MMBtu/hour of Duct Burning

Gulf Power - Lansing Smith Combined Cycle Gas Turbines w/Duct Burning							
		Unit 4 (3/21/2002)			Unit 5 (3/27/2002)		
Parameter	Units	1	2	3	1	2	3
H.I.	MMBtu/hr	2057	2080	2083	2049	2081	2095
CO	ppmvd @ 15% O2	0.98	1.31	1.34	1.30	1.25	1.21
VOC	ppmvd @ 15% O2	0.16	0.15	0.15	0.54	0.23	0.15

Table 6-2. GE Frame 7FA Gas Turbine w/Power Augmentation (Steam Injection)

Gulf Power's Lansing Smith Combined Cycle Gas Turbines w/Power Augmentation							
		Unit 4 (4/5/2002)			Unit 5 (4/12/2002)		
Parameter	Units	1	2	3	1	2	3
H.I.	MMBtu/hr	2106	1982	2004	1950	1949	1953
CO	ppmvd @ 15% O2	4.62	4.67	6.26	8.97	8.12	8.76
VOC	ppmvd @ 15% O2	1.11	0.22	0.50	0.34	0.38	0.42

The CO limits for Units 4 and 5 are 16/23 ppmvd @ 15% O_2 for duct burning/power augmentation. The VOC limits for Units 4 and 5 are 4/6 ppmvd @ 15% O_2 for duct burning/power augmentation. The Department notes little difference in CO and VOC emissions between normal operation and duct burning. The already high combustion temperatures and available oxygen content of the gas turbine exhaust gas (11% to 14%) provide the efficient combustion characteristics necessary to maintain low CO emission levels. However, it is noted that steam injection for power augmentation is shown to have a measurable affect on CO emissions.

As shown by specific test data, CO emissions are much lower than recent permit limits and manufacturer's guarantees. Such low actual CO emissions would tend to drive the cost effectiveness of a catalytic oxidation system even higher. The Department determines that add-on controls to further reduce CO emissions are unwarranted given the low emissions characteristics of this particular gas turbine and the firing of natural gas as the primary fuel. Therefore, a catalytic oxidation system is rejected as not cost effective for this specific project.

Based on the available information regarding duct burning, no separate standard will be established. A slightly higher CO standard will be specified for power augmentation, which is limited to no more than 400 hours per year for each gas turbine. The Department establishes the following draft BACT standards.

a. Oil Firing: 15.0 ppmvd @ 15% O_2, 24-hour block average
b. Gas Firing (with or without duct burning): 8.0 ppmvd @ 15% O_2, 24-hour block average
c. Gas Firing With Power Augmentation: 12 ppmvd @ 15% O_2, 24-hour block average

The "24-hour block average" is defined as the daily average for the actual hours operated in that mode. For example, assume the unit operates 20 hours of normal operation and 4 hours with power augmentation. Then, two separate compliance determinations would be made for the day: one for normal gas firing based on an average of 20 hourly values and one for power augmentation based on an average of 4 hourly values. This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance with the CO standard will be demonstrated by continuous emissions monitoring system (CEMS). Continuous monitoring has been standard practice for recent Department determinations for combined cycle gas turbine projects.

7. DRAFT BACT STANDARDS – VOLATILE ORGANIC COMPOUNDS

Discussion

VOC emissions result from incomplete combustion when firing natural gas and distillate oil. Large combustion turbines offer high temperatures with efficient combustion resulting in relatively low levels of volatile organic compounds. For this project, VOC emissions from one gas turbine are expected to be less than 25 tons per year. Similar to the control of carbon monoxide, catalytic oxidation systems are available for reducing VOC emissions from gas turbines. Catalytic oxidation systems can achieve emissions reductions approaching 90% depending on the uncontrolled inlet VOC emission rate. However, such a system was determined to be not cost effective for the control of CO emissions.

Applicant's Proposal

The applicant proposes the following emissions standards based on efficient combustion of natural gas and distillate oil and good operating practices for the gas turbines.

- Oil Firing: 3.5 ppmvw (2.5 ppmvd @ 15% O_2)
- Gas Firing: 1.5 ppmvw (1.3 ppmvd @ 15% O_2)
- Gas Firing with Duct Firing: 7 ppmvw (4.9 ppmvd @ 15% O_2)

The applicant proposes to demonstrate compliance with the standards by conducting performance tests in accordance with EPA Methods 18, 25, and 25A.

Department's Draft VOC BACT Determinations

As discussed previously, the Department agrees that a catalytic oxidation system is not cost effective for this project. Therefore, the efficient combustion design and good operating practices are determined to represent the Best Available Control Technology. Based on the test data previously presented, the Department believes VOC emissions will be much lower than estimated by the applicant. The following are established as the draft BACT standards.

- Oil Firing: 2.5 ppmvd @ 15% O_2
- Gas Firing: 1.3 ppmvd @ 15% O_2
- Gas Firing with Duct Burning: 4.0 ppmvd @ 15% O_2

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance shall be demonstrated by conducting performance tests in accordance with EPA Method 25A. EPA Method 18 may also be performed to deduct emissions of methane and ethane that are excluded from the definition of "VOC".

8. DRAFT BACT STANDARDS - PARTICULATE MATTER

Discussion – Gas Turbines

Emissions of particulate matter will result from incomplete combustion of natural gas and distillate oil as well as contaminants in these fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in a given fuel. However, natural gas is a clean fuel containing little ash, sulfur, or other contaminants. Similarly, distillate oil contains little of these contaminants and is restricted to only 500 hours per year per gas turbine for this project. Attachment A shows typical BACT determinations for particulate matter from large gas turbine projects. Some of the projects include front and back half catch for PM limits; therefore, comparison is not simple. Emissions of particulate matter when injecting ammonia for NOx control may be higher due to the formation of fine particulates such as ammonia sulfates and bisulfates.

Applicant's Proposal – Gas Turbines

At the estimated uncontrolled emission rates when firing natural gas, the applicant states that installation of add-on controls such as baghouses or electrostatic precipitators would be cost prohibitive. In addition to firing natural gas and very low sulfur distillate oil, the applicant proposes the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standard.

- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Department's Draft PM BACT Determinations – Gas Turbines

The total potential emissions from a single gas turbine are estimated to be about 60 tons per year. Actual test data indicates that particulate matter emissions may actually be one-tenth of this level. The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive for large gas turbines firing primarily natural gas with restricted amounts of very low sulfur distillate oil. The specification of clean fuels is a pollution prevention technique and is given favorable consideration for this project. Therefore, the following conditions are established as the draft BACT standards.

- The gas turbines 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 duct burners are limited to firing only natural gas meeting this specification. The gas turbines may fire distillate oil as a restricted alternate fuel ($\leq$ 500 hours per year), which shall contain no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance with the fuel specifications shall be determined by records of the fuel analyses. Compliance with the visible emissions standard will be demonstrated by conducting at least annual opacity observations in accordance with EPA Method 9. In addition, the CO CEMS standard will serve a continuous indication of efficient combustion practices to minimize emissions of particulate matter.

Cooling Tower PM Emissions: The applicant's preliminary design includes an 18-cell mechanical draft cooling tower with the following specifications: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water. The Department determines the draft BACT to be a design drift rate of no more than 0.001% of the circulating water flow rate. At this level, maximum potential particulate matter emissions are expected to be 34 tons per year or about 10% of the maximum potential particulate matter emissions from the project. Actual particulate matter emissions are expected to be 34 tons per year.

9. DRAFT BACT STANDARDS – SULFURIC ACID MIST AND SULFUR DIOXIDE

Discussion

Emissions of sulfur dioxide (SO_2) are generated from fuel sulfur with small amounts of SO_2 being converted to sulfuric acid mist (SAM). Natural gas is a clean fuel containing little ash, sulfur, or other contaminants. The distillate oil specified for this project also contains very low sulfur levels.

Applicant's Proposal

The applicant states that flue gas desulfurization systems are not available, technically feasible, demonstrated nor cost effective for gas turbines. The applicant proposes the use of clean fuels as previously specified to limit emissions of SAM and SO_2 from the project.

Department's Draft SAM/SO_2 BACT Determinations

The potential emissions from a single gas turbine are estimated to be 70 tons of SO_2 per year and 7.5 tons of SAM per year. Given the high flow rates and estimated low emission levels, the Department agrees that installation of add-on flue gas desulfurization equipment is not reasonable. All of the recent gas turbine projects (Attachment A) control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. The projects ultimately rely on a fairly uniform gas distribution network, which typically provides natural gas with a fuel sulfur content of less than 1 grain per 100 SCF of gas. Distillate oil will be brought to the plant by truck and the vendor must meet contractual specifications regarding the fuel sulfur content. The Department determines that the following fuel specifications represent the Best Available Control Technology for limiting emissions of SAM and SO_2 from the project.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF. The duct burners are limited to firing only natural gas meeting this specification.
- The gas turbines may fire distillate oil containing no more than 0.05% sulfur by weight as a restricted alternate fuel.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. The above fuel specifications effectively limit potential emissions of SAM and SO_2 emissions, is typically considered BACT for similar gas turbine projects, and is clearly more stringent than the NSPS Subpart GG standard of 0.8% sulfur by weight for gas turbines. Compliance with the fuel specifications shall be determined by records of the fuel analyses.

10. DRAFT STANDARDS FOR AMMONIA SLIP EMISSIONS

Ammonia is injected into the exhaust gas stream as part of the selective catalytic reduction (SCR) system that is used to control NOx emissions. Some of the ammonia will escape past the catalyst without reaction as "ammonia slip" or combine with sulfur to form fine particulate matter such as ammonium sulfates and bisulfates. Elevated levels of ammonia slip may indicate a degrading catalyst. Limiting ammonia slip will also minimize the formation of fine particulate matter formation previously mentioned. Therefore, the following draft ammonia slip standard is specified.

- The SCR system shall be designed and operated for a maximum ammonia slip level of 5 ppmvd @ 15% O_2.

This determination is consistent with recent Department determinations for combined cycle gas turbine projects in Florida. Compliance with the ammonia slip level shall be demonstrated at least annually in accordance with EPA's Conditional Test Method No. 27. Ammonia has been designated as a hazardous substance under federal SARA Title III regulations and must be carefully managed to prevent accidental spills or nitrogen loading of the waters and soils.

11. NSPS REQUIREMENTS

Gas Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NOx (gas) ≤ 110 ppmvd @ 15% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NOx (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

Duct Burners

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 495 MMBtu per hour. This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NOx ≤ 1.6 lb/MW-hr (gross)
- SO_2 ≤ 0.20 lb/MMBtu
- PM ≤ 0.03 lb/MMBtu

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.07 lb/MW-hr for NOx, 0.008 lb/MMBtu for PM, and less than 0.02 lb/MMBtu for PM (oil firing with ammonia injection), which readily complies with the NSPS standards. An Appendix to the permit will summarize applicable federal requirements.

Gas-Fired Fuel Heaters

The gas-fired fuel heaters each have a maximum heat input rate of 22 MMBtu per hour. The fuel heaters are subject to the federal New Source Performance Standards in Subpart Dc of 40 CFR 60 based on the definition of "steam generators" in that rule. However, such units firing only natural gas are subject to only notification and record keeping requirements. As work practice standards that represent BACT for all pollutants, the draft permit includes: a fuel specification for natural gas (2 grains per 100 SCF of gas) and an opacity limit (10% opacity except for one 6-minute period per hour during which the opacity shall not exceed 20%.)

12. MACT 112(g) APPLICABILITY

EPA is required to promulgate Maximum Available Control Technology (MACT) standards for hazardous air pollutant (HAP) emissions from gas turbines. Because EPA has not yet proposed these standards, states are required to review new projects for the applicability of 112(g). If emissions are 10 tons per year or more of any single HAP or 25 tons per year or more of all combined HAPs, new projects could be subject a case-by-case MACT determination. The applicant estimated total HAP emissions from the proposed project to be less than 15 tons per year, which would not trigger the 112(g) requirement.

In the memorandum dated August 21, 2001, EPA states that the original HAP emissions information (EPA memorandum dated 12/30/99) was based primarily on existing diffusion flame combustor technology. This technology results in higher emissions of CO, NOx, and HAPs than lean pre-mix combustor designs, such as General Electric's dry low-NOx combustion technology. Based on additional emissions performance testing, EPA states that the average formaldehyde emissions factor is 6.49 x 10^{-05} lb/MMBtu for large gas turbines (10

MW to 170 MW) utilizing lean premix combustion. Because formaldehyde had the highest emission rate for HAPs, it is reasonable to assume that other HAPs would also be much lower for lean premix combustion.

One theory for the much lower HAP emission levels is that, although the premixing of fuel and air with staged entry limits flame temperature and residence time at peak flame temperatures, it also reduces "cold spots" throughout the combustion zone providing more uniform destruction. EPA also states that, "For purposes of monitoring HAP performance of lean premix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions." The Department believes that the project has potential HAP emissions of less than 10 tons per year for all individual HAPs and less than 25 tons per year for all combined HAPs. Based on all of the available information, a case-by-case 112(g) MACT determination is not required for this project. Each gas turbine will continuously monitor CO and NOx emissions, which will ensure proper lean premix combustor performance and thereby low HAP emissions.

13. PERIODS OF EXCESS EMISSIONS

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 NOx emissions.

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.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Recent conversations indicate that full lean premix operation may occur between 40% and 50% of base load, but this has not yet been verified. During a startup to simple cycle mode, the gas turbine will not reach lean premix operation (50% load) until about 15 minutes into the start (perhaps 30 minutes for a hot nozzle combustor design). Therefore, emissions for this 15-minute period will be greater than the permitted emissions standards. Shutdowns offer similar performance. In addition, a startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup to combined cycle operation, up to three hours of excess emissions are allowed. "Warm

startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 24 hours.

- For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 48 hours.
- For shutdown from combined cycle operation, up to three hours of excess emissions are allowed.
- For days with simple cycle operation, excess emissions shall not exceed three hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For days with combined cycle operation, excess emissions shall not exceed four hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions.
- For startup to combined cycle operation, ammonia 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 NOx 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.

Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. During the steam blows, the following conditions apply:

- The permittee shall take all precautions to minimize the extent and duration of excess emissions.
- Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.
- CO and NOx emissions may exceed the BACT limits specified in this permit; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within 24-hours of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. {Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods.} [Design; Rules 62-212.400(BACT) and 62-210.700(5), F.A.C.]

Combined Cycle Operation With Dump Condenser: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Although this method of operation is inefficient, it may be preferable due to the time necessary to shutdown, cool, and prepare the units for simple cycle operation. Apparently, a baffle plate must be unbolted, removed and repositioned for simple cycle operation, which takes at least a day. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

14. DEPARTMENT'S ESTIMATED ANNUAL EMISSIONS

The following table shows the estimated annual emissions from the completed combined cycle unit based on the draft permit conditions.

Pollutant	Project Emissions, TPY
CO	589
Pb	0.03
NOx	683
PM	288
SO_2	276
SAM	30
VOC	75

15. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project 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. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

Major Stationary Sources in Martin County

The current largest stationary sources of air pollution in Martin County are listed below:

TABLE 15-1. MAJOR SOURCES OF SO_2 IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant (Existing boilers)	15,573
Indiantown	Indiantown	1,870
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*280**

* Potential emissions

TABLE 15-2. MAJOR SOURCES OF NO_X IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant	6,425
Indiantown	Indiantown	2,136
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*683**

* Potential emissions

TABLE 15-3. MAJOR SOURCES OF VOC IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Louis Dreyfus	Louis Dreyfus	245
Florida Power and Light	Martin Power Plant (Existing boilers)	170
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*110*/75*

* Potential emissions based on application. Revised downward based on Department's draft BACT Determination.

TABLE 15-4. MAJOR SOURCES OF PM IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant (Existing boilers)	1,452
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*322**
Indiantown	Indiantown	119

* Potential emissions

TABLE 15-5. MAJOR SOURCES OF CO IN MARTIN COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Martin Power Plant (Existing boilers)	11,345
Florida Power and Light	*Martin Power Plant (Proposed turbines)*	*826**
Indiantown	Indiantown	130

* Potential emissions

Air Quality and Monitoring in the Martin County

The Martin County Region has five monitors at four sites measuring PM_{10}, ozone, CO, SO_2 and NO_2. The 2001 monitoring network is shown in Figure 15-1 at the right.

Measured ambient air quality is given in Table 15-6 on the following page. The highest measured values are all less than the respective National Ambient Air Quality Standards. The average measurements are all less than the respective standards.

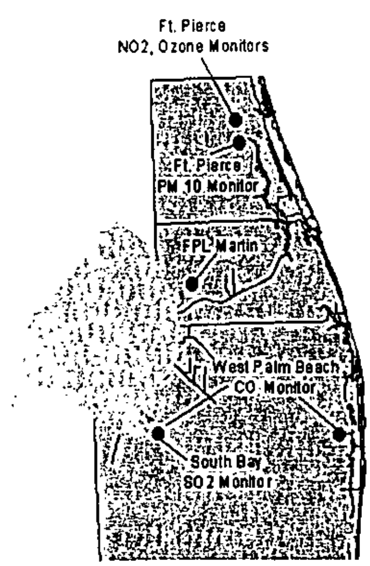


Figure 15-1. Martin County Regional Monitoring Network

TABLE 15-6. 2000 AMBIENT AIR QUALITY NEAR PROJECT SITE

Pollutant	Site Location			Averaging Period	Ambient Concentration				
	City	Site no.	UTM		1st High	2nd High	Mean	Standard	Units
PM_{10}	Ft. Pierce	111-0012	17-3029.7N-559.4E	24-hour	37	35		150[a]	ug/m^3
				Annual			18	50[b]	ug/m^3
SO_2	South Bay	099-2101	17-2949.5N-528.5E	3-hour	15	9		500[a]	ppb
				24-hour	4	3		100[a]	ppb
				Annual			2	20[b]	ppb
NO_2	Ft. Pierce	111-1002	17-3036.2N-558.5E	Annual			10	53[b]	ppb
CO	West Palm Bch	099-1006	17-2952.4N-589.5E	1-hour	4	4		35[a]	ppm
				8-hour	3	3		9[a]	ppm
Ozone	Fort Pierce	111-1002	17-3036.2-558.5E	1-hour	0.082	0.079		0.12[c]	ppm

a - Not to be exceeded more than once per year.

b - Arithmetic mean.

c - Not to be exceeded on more than an average of one day per year over a three-year period.

Air Quality Impact Analysis

Significant Impact Analysis: For PM/PM_{10}, CO, NO_X and SO_2, which have significant impact levels defined for them, a significant impact analysis is performed. 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 in 6.5.4. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and II Areas.

If this modeling at worst-load conditions shows significant impacts, additional modeling, which includes the emissions from surrounding facilities, or multi-source modeling is required to determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

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 (except for 24-hour SO_2) are less than the applicable "significant impact levels." These values are tabulated in the table on the following page and compared with existing ambient air quality measurements from the local ambient monitoring network.

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area (except for 24-hour SO_2). They are also less than the respective significant impact levels (except for 24-hour SO_2) that would otherwise require more detailed modeling efforts. The maximum predicted 24-hour SO_2 impacts are approximately equal to the baseline concentrations collected at the SO_2 monitor, which is located in a rural area. However, these predicted concentrations are much less than the AAQS. In the case of 24-hour SO_2, additional modeling was required, which showed maximum impacts from all sources in the area were much lower than the AAQS. The results of this modeling are given in Table 15-7.

TABLE 15-7. MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE FPL PROJECT FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.6	1	~5	60	NO
	24-Hour	9	5	~10	260	YES
	3-Hour	18	25	~40	1300	NO
PM_{10}	Annual	0.3	1	~20	50	NO
	24-Hour	4.4	5	~40	150	NO
CO	8-Hour	8	500	~3300	10,000	NO
	1-Hour	20	2000	~4500	40,000	NO
NO_2	Annual	0.6	1	~10	100	NO

The nearest PSD Class I area is the Everglades National Park (ENP) located about 145 km to the south. The applicant's initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable significant impact levels (except for 24-hour SO_2) for the Class I area. These values are tabulated below. Note that the values are miniscule if compared with the ambient air quality standards given in the previous table. Since these impacts are less than the respective significant impact levels, no further detailed modeling efforts are required in this Class I area (except for 24-hour SO_2). In the case of 24-hour SO_2, additional modeling was required, which showed impacts from all sources in the area were lower than the PSD Class I increment, which in turn, is much lower than the AAQS. The results of the 24-hour SO_2 multi-source PSD Class I increment are presented in Table 15-8.

TABLE 15-8. MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE FPL PROJECT COMPARED WITH PSD CLASS I SIGNIFICANT IMPACT LEVELS (EVERGLADES)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	NO
	24-hour	0.07	0.3	NO
NO_2	Annual	0.002	0.1	NO
SO_2	Annual	0.001	0.1	NO
	24-hour	0.4	0.2	YES
	3-hour	0.7	1	NO

Preconstruction Ambient Monitoring Requirements

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 uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in Table 15-9, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

TABLE 15-9. MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMUS AMBIENT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~40	NO
NO_2	Annual	1	14	~10	NO
SO_2	24-hour	9	13	~10	NO
CO	8-hour	16	575	~3300	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 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. Although the applicant estimated annual potential VOC emissions from the project to be greater than 100 tons per year, the draft permit limits VOC emissions below 100 tons per year. Therefore, preconstruction monitoring for ozone is not required. The three regional ozone monitors in the area (West Palm Beach and Ft. Pierce) suffice for any background ozone pre-construction monitoring requirements.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for 24-hour SO_2 in the Class II area in the vicinity of the project and the ENP Class I area;
- An analysis of impacts on ground level ozone; and
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. 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.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Palm Beach International Airport. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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 CNWA. Meteorological data used in this model was from 1990. Meteorological surface data used were from Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers, Key West, Miami and Orlando. Meteorological upper air data used were from Ruskin, Key West and West Palm Beach. Hourly precipitation data were obtained from 23 stations around the central and southern part of the state.

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 AAQS SO_2 Analysis

For pollutants subject to a multi-source 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, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

TABLE 15-10. AMBIENT AIR QUALITY IMPACTS

Pollutant	Averaging Time	Major Source Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
SO_2	24-hour	75	10	85	NO	260

Multi-source PSD Class II Increment Analysis for SO_2

The multi-source PSD increment represents the amount that all new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration, which was established in 1977 for SO_2 (the baseline year was 1975 for existing major sources of SO_2). The maximum predicted 24-hour SO_2 PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of FPL Martin are shown in the following table. As shown, the maximum predicted impacts are much less than the allowable Class II SO_2 increments.

TABLE 15-11. PSD CLASS II INCREMENT ANALYSIS

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Impact Greater Than Allowable Increment?	Allowable Increment (μg/m^3)
SO_2	24-hour	41	NO	91

Multi-source PSD Class Increment Analysis for SO_2

The maximum predicted 24-hour SO_2 PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table. As shown, the maximum predicted impacts are less than the allowable Class I 24-hour SO_2 increment in the ENP.

TABLE 15-12. PSD CLASS I INCREMENT ANALYSIS – ENP

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater Than Allowable Increment?	Allowable Increment ($\mu g/m^3$)
SO_2	24-hr	3.5	NO	5

Ozone Impact Assessment

The Department's draft BACT will limit the VOC emissions increase to 75 tons per year. These emissions will be less than the 100 tons per year significant impact level, which would require an ambient air quality analysis. Therefore modeling of impacts on ozone due to VOC emissions is not required.

Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife: Very low emissions are expected from the natural gas and distillate oil fired 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. In addition, the project impacts for PM_{10}, CO and NO_X are less than the significant impact levels, which, in turn, are less than the applicable allowable increments for each pollutant. The AAQS are designed to protect both the public health and welfare. 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, or wildlife will be minimal or insignificant.

Impact On Visibility and Regional Haze: Natural gas and low sulfur distillate fuel oil are clean fuels that contain little ash or other contaminants. The low NO_X and SO_2 emissions will also minimize plume opacity. The contribution to smog in the area will be minimal. The applicant submitted a regional haze analysis for the ENP. Based on NPS criteria, no adverse impacts are predicted.

Growth-Related Air Quality Impacts: There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area.

16. 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 determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the air quality impact analysis. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Table A-1. Recent NOx Standards Proposed for "F-Class" Simple Cycle Gas Turbine Projects in the Southeast

Project Location	Capacity (MW)	NOx Limit ppmvd @ 15% O_2	Technology	Comments
El Paso Manatee, FL	350	9 NG	DLN	2x175 MW GE 7FA CTs (Gas only
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Draft 8/2001. Gas Only
Enron Deerfield, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 500 hrs on oil
Enron Pompano, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Revised Draft 06/01. 500 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE 7FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.

Notes:

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
CT = Combustion Turbine
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Table A-2. Recent CO, PM, and VOC Standards for "F-Class" Simple Cycle Gas Turbine Projects in the Southeast

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
El Paso Manatee, FL	8 (7.4@15% O_2) - N	1.4 (1.3@15% O_2)	18 lb/hr (Front & Back	Clean Fuels Good Combustion
El Paso Deerfield, FL	8 (7.4@15% O_2) - NG	1.4 (1.3@15% O2)	18 lb/hr (Front & Back)	Clean Fuels Good Combustion
Enron Deerfield, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion

Notes:

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
CT = Combustion Turbine
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Table A-3. Recent NOx Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast

Project Location	Capacity MW	NOx Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
El Paso Manatee, FL	250	2.5 – NG	SCR	175 MW GE 7FA
El Paso Deerfield, FL	250	2.5 – NG	SCR	175 MW GE 7FA Draft 8/2001
CPV Pierce, FL	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT 7/2001
Metcalf Energy, CA	600	2.5 – NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce, FL	~250	3.5 – NG 10 - FO	SCR	170 MW MHI501F CT Repowering
CPV Atlantic, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
CPV Gulfcoast, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
TECO Bayside, FL	1750	3.5 – NG 12 - FO	SCR	7x170 MW GE 7FA CTs, Repowering
FPC Hines II, FL	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F
Calpine Osprey, FL	527	3.5 – NG	SCR	2x170 MW WH501F Draft 5/00
Calpine Blue Heron, FL	1080	3.5 – NG	SCR	4x170 MW WH501F Draft 2/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG 15 - FO	SCR	170 MW GE 7FA. 11/99
Lake Worth LLC, FL	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98

Notes:

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
CT = Combustion Turbine
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Table A-4. Recent CO, PM, and VOC Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast

Project Location	CO - ppmvd (or lb/MMBtu)	VOC - ppmv (or lb/MMBtu)	PM - lb/MMBtu (or gr/dscf or lb/hr)	Technology and Comments
El Paso Manatee, FL	9 (7.4 @15% O_2) 15 (12 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Deerfield, FL	9 (7.4 @15% O2) 15 (12 @15% O2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Pierce, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/MMBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Enron Ft. Pierce, FL	3.5 - NG 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity	Oxidation Catalyst Clean Fuels Good Combustion
CPV Atlantic, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Gulfcoast, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	9 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)	1.3 – NG 3 - FO	12 lb/hr – NG 30 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	16 - NG (24-hr CEMS) 30 – FO (24-hr CEMS)	2 – NG 10 – FO	10% Opacity – NG 5/9 ammonia – NG/FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Calpine Blue Heron, FL	10 – NG (24-hr CEMS) 17 – NG (DB&PA)	1.2 – NG 6.6 – NG (DB&PA)	31.9 lb/hr – NG (DB&PA) 10 percent Opacity 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry, AL	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/MMBtu – (CT) 0.011 lb/MMBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
KUA Cane Island, FL	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel,	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/MMBtu – (CT) 0.011 lb/MMBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion

Notes:

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
CT = Combustion Turbine
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

DRAFT PERMIT

PERMITTEE:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

FPL Martin Power Plant Project No. 0850001-010-AC Air Permit No. PSD-FL-327 SIC No. 4911 Expires: December 30, 2005

PROJECT AND LOCATION

This permit authorizes the construction of Unit 8, a nominal 1150-megawatt "4-on-1" combined cycle unit at the existing Martin Power Plant. The project will utilize two existing 170 MW gas turbine-electrical generator sets and will add two new 170 MW gas turbine-electrical generator sets, four new heat recovery steam generators, a single nominal 470 MW steam turbine-electrical generator, gas-fired fuel heaters, and a mechanical draft cooling tower. The existing Martin Power Plant is located approximately 7 miles north of Indiantown on State Road 710 in Martin County, Florida.

UTM Zone 17; 543.1 km East; 2992.9 km North (Latitude: 27° 03' 1", Longitude: 80° 33' 46")

STATEMENT OF BASIS

This PSD air pollution 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.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting and was therefore processed in accordance with Florida's delegated 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

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

FACILITY DESCRIPTION

The existing Martin Power Plant currently consists of six electrical generating units. Fossil fuel-fired steam electric generators Units 1 and 2 (863 MW each) began operation in 1980 and 1981, respectively. Combined cycle gas turbine Units 3A/3B and 4A/4B (430 MW each) began operation in 1994. Existing simple cycle gas turbine Units 8A and 8B (170 MW each) began operation in 2001. Units 8A and 8 B will be incorporated into the new "4 on 1" combined cycle Unit 8, which will consist of two new gas turbine Units 8C and 8D (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. Unit 8 will have a total generating capacity of 1150 MW. After completion of this project, the plant will have a nominal generating capacity of 3610 MW.

NEW AND MODIFIED EMISSIONS UNITS

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

ID	Emission Unit Description
011	Unit 8A gas turbine (170 MW) with heat recovery steam generator
012	Unit 8B gas turbine (170 MW) with heat recovery steam generator
013	Gas-fired fuel heaters
017	Unit 8C gas turbine (170 MW) with heat recovery steam generator
018	Unit 8D gas turbine (170 MW) with heat recovery steam generator
019	Mechanical draft cooling tower for Unit 8

Note: Martin Unit 8 consists of four gas turbine-electrical generator sets (Units 8A-8D), four gas-fired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is not major for HAPs.

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: The following New Source Performance Standards (NSPS) apply to this project: 40 CFR 60, Subpart Da (gas-fired duct burners); 40 CFR 60, Subpart Dc (gas-fired fuel heaters); and 40 CFR 60, Subpart GG (gas turbines).

NESHAP: No emissions units are identified as subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP).

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, Post Office Box 15425, West Palm Beach, Florida 33416-5425.

APPENDICES

The following Appendices are attached as part of this permit.

- Appendix A. Citation Format and Definitions
- Appendix BD. Final BACT Determinations and Emissions Standards
- Appendix Da. NSPS Subpart Da Requirements for Gas-Fired Duct Burners
- Appendix Dc. NSPS Subpart Dc Requirements for Gas-Fired Fuel Heaters
- Appendix GC. Construction Permit General Conditions
- Appendix GG. NSPS Subpart GG Requirements for Gas Turbines
- Appendix SC. Standard Conditions

RELEVANT DOCUMENTS

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

- Permit application received on 02/01/02 and all related completeness correspondence.
- Draft permit package issued on (Draft).
- Comments received from the public, the applicant, the EPA Region 4 Office, and the National Park Service.

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. 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, phasing of the project, or an extension of the permit expiration date, the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (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.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]

4. 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.]

5. Modifications: No emissions unit or facility subject to this permit 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. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. 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 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 Department's Bureau of Air Regulation with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. UNIT 8 – "4 ON 1" COMBINED CYCLE GAS TURBINE

This section of the permit addresses the following emissions units.

Emissions Units 011, 012, 017, 018

Description: Emissions units 011, 012, 017, and 018 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a bypass stack, a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit is 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions during simple cycle operation. A selective catalytic reduction (SCR) system in combination with the other NOx controls further reduces NOx emissions during combined cycle operation.

Stack Parameters: Each gas turbine has a bypass stack (80 feet tall and 22.0 feet in diameter) and each heat recovery steam generator has a HRSG stack (120 feet tall and 19.0 feet in diameter). The following summarizes the exhaust characteristics:

			Simple Cycle Operation		Combined Cycle Operation	
Fuel	Heat Input Rate	Compressor Inlet Temp.	Exhaust Temp.	Flow Rate ACFM	Exhaust Temp., °F	Flow Rate ACFM
Gas	1600 MMBtu/hour	59° F	1116° F	2,389,500	202° F	1,004,200
Oil	1811 MMBtu/hour	59° F	1098° F	2,735,300	295° F	1,193,900

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx 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 (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and 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 Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable Subpart GG and Subpart Da requirements are summarized in Appendices Dc and GG of this permit. [Rule 62-204.800(7), F.A.C.]

EQUIPMENT

3. Gas Turbine Units 8C and 8D: The permittee is authorized to install, tune, operate, and maintain two new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 017 and 018). Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation that is 80 feet tall and 22.0 feet in diameter. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters (EU 013) will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: Two existing simple cycle General Electric Model PG7241FA gas turbine-electrical generator sets, Units 8A and 8B (EU 011 and 012), will be incorporated into the "4-on-1" combined cycle Unit 8.}* [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NOx emissions below permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to reduce NOx emissions below permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to meet the NOx emission standard on a 1-hour basis.

   c. *(SCR) System*: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed and operated to reduce NOx emissions and ammonia slip below the permitted levels. *{Permitting Note: The ammonia tank will store aqueous ammonia having a concentration of less than 20 percent ammonia. In accordance with 40 CFR 60.130, it is not subject to the Chemical Accident Prevention Provisions of 40 CFR 68.}*

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

5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG shall include an exhaust stack that is 120 feet tall and 19.0 feet in diameter. To minimize the number of cold startups to combined cycle operation, each HRSG system shall include a damper in the ductwork before the stack to reduce heat loss during shutdowns. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}* [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The heat input rate to each gas turbine shall not exceed 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total heat input rate to the duct burners for each HRSG shall not exceed 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

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

   a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

   c. *Simple Cycle Operation*: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

      (1) Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

      (2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours during any consecutive 12 months.

   d. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and deliver steam to the steam turbine-electrical generator to produce steam-generated electrical power as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the manufacturer's specifications, the SCR system shall be on line and functioning properly during combined cycle operation.

   e. *Inlet Fogging*: 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. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

   f. *Peaking*: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Each gas turbine shall operate in the power augmentation mode for no more than 400 hours during any consecutive 12 months. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours during any consecutive 12 months.

h. *Combined Cycle Operation with Duct Firing*: When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. Each HRSG shall fire the duct burners no more than 2880 hours during any consecutive 12 months.

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

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Initial		CEMS
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO [a]	Oil	Simple or Combined Cycle	14.4, 3-hr	64.7	15.0, 24-hr
	Gas	Simple or Combined Cycle	7.4, 3-hr	27.5	8.0, 24-hr
		Combined Cycle w/DB	7.4, 3-hr	37.5	8.0, 24-hr
		Simple or Combined Cycle w/PA	12.0, 3-hr	45.0	12.0, 24-hr
		Combined Cycle w/DB+PA	12.0, 3-hr	55.6	12.0, 24-hr
NOx [b]	Oil	Simple Cycle	42.0, 3-hr	319.2	42.0, 3-hr
		Combined Cycle – SCR	10.0, 3-hr	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0, 3-hr	58.7	9.0, 24-hr
		Simple Cycle w/PA	NA	(76.2)	12.0, 1-hr
		Simple Cycle w/Peaking	NA	(101.3)	15.0, 1-hr
		Combined Cycle – SCR	2.5, 3-hr	16.3	2.5, 24-hr
		Combined Cycle w/DB – SCR	2.5, 3-hr	22.1	2.5, 24-hr
PM/PM_{10} [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute average as determined by EPA Method 9 observations.		
SAM/SO_2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5, 3-hr	6.0	NA
	Gas	Simple or Combined Cycle	1.3, 3-hr	2.8	NA
		Combined Cycle, w/DB or PA	4.0, 3-hr	9.2	NA
Ammonia [f]	Oil/Gas	Combined Cycle – SCR	5.0, 3-hr	NA	NA

Note: "DB" means duct burning. "PA" means power augmentation.

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the NOx standard for simple cycle operation with peaking or power augmentation shall be demonstrated on an hour-to-hour basis with CEMS data. CEMS data collected during simple cycle peaking or power augmentation shall be excluded from the data used to demonstrate compliance with the 24-hour standard for normal operation. *{Permitting Note: The "lb/hour" rates for simple cycle peaking or power augmentation are for informational purposes only.}*

c. The fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: PM_{10} emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM_{10} emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

d. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 28 of this section. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO_2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

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

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

10. <u>Combined Cycle Operation With Dump Condenser</u>: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by transferring steam to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection. *{Permitting Note: Although this method of operation is inefficient, it may be preferable due to the time necessary to shutdown, cool, and prepare the units for simple cycle operation.}* [Application]

11. <u>Duct Burners</u>: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. [Subpart Da, 40 CFR 60]

PROJECT PHASE-IN

12. Existing Simple Cycle Units: For existing Units 8A and 8B (EU 011 and 012), this PSD permit shall replace and supersede previously issued PSD permit (No. PSD-FL-286) upon commencement of the initial steam blows. [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

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

15. 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.]

16. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, 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 gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.

    a. For warm startup to combined cycle operation, up to three hours of excess emissions are allowed. "Warm startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 24 hours.

    b. For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup to combined cycle operation following a shutdown lasting at least 48 hours.

    c. For shutdown from combined cycle operation, up to three hours of excess emissions are allowed.

    For days with simple cycle operation, excess emissions shall not exceed three hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For days with combined cycle operation, excess emissions shall not exceed four hours in any 24-hour period due to all combined occurrences of startups, shutdowns, and malfunctions. For startup to combined cycle operation, ammonia injection shall begin as soon as operation of the gas turbine/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, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

17. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete

this process within 90 days of conducting the initial steam blow. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

c. CO and NOx emissions may exceed the BACT limits specified in this permit; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within 24-hours of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. *{Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods.}* [Application]

18. 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 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

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

Method	Description of Method and Comments
CTM-027	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.}
5	Determination of Particulate Matter Emissions from Stationary Sources
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.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

20. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial 3-hour CO and NOx standards. With appropriate flow measurements and calculations, CEMS data may also be used to demonstrate compliance with the CO and NOx mass emissions standards. CO and NOx 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 initial tests after the replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C.]

21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (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, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx 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.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

23. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine 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 and commencement of commercial operation. Within one working day of discovering emissions in excess of a CO or NOx standard, the permittee shall contact the Compliance Authority.

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. 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 shall have multi-span capability with appropriate spans established for the methods of operation (simple cycle gas firing, combined cycle gas firing, simple cycle oil firing, combined cycle oil firing, etc.). {Permitting Note: The alternate standards for steam blows will require even higher span values.}

    b. *NOx Monitors.* Each NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. 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. The NOx monitor shall have multi-span capability with appropriate spans established for the methods of operation (simple cycle gas firing, combined cycle gas firing, simple cycle oil firing, combined cycle oil firing, etc.). {Permitting Note: The alternate standards for steam blows will require even higher span values.}

c. *O_2 or CO_2 Monitors.* The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and/or NOx 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 by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. 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 O_2 or CO_2 monitors shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. 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 NOx as specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *3-hour Block Averages*: For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *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 available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. {Permitting Note: There may be more than one 24-hour compliance demonstration for CO and NOx emissions depending on the use of alternate methods of operation. [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, and malfunction. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of

Condition No. 16 of this section. All periods of data excluded shall be consecutive for each such episode. 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.

h. *Availability*. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit 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.

{Permitting Note: Compliance with these requirements ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; 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; and 40 CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

24. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. During NOx monitor downtimes or malfunctions, the permittee shall operate at the water-to-fuel ratio that is consistent with the documented flow rate for the gas turbine load condition. {Permitting Note: The water-to-fuel ratio at maximum load to achieve the NOx standards during simple cycle oil firing is approximately 1.10 or a water injection rate of approximately 101,000 pounds per hour.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document 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 NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is 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

26. Monitoring of Capacity: To demonstrate compliance with the permitted capacities, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system 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.]

27. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of

operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, 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.]

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

   a. 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, D3246-81 or more recent versions.

   b. Compliance with the distillate 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 D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

29. Excess Emissions Notification: If a CEMS reports emissions in excess of an emissions standard or the permittee observes visible emissions in excess of a standard, the permittee shall notify the Compliance Authority within one working day of occurrence. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-210.700, F.A.C.]

30. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

31. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. GAS-FIRED FUEL HEATERS

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
013	Four gas-fired fuel heaters, 22 MMBtu/hour each

APPLICABLE REQUIREMENTS

1. NSPS Requirements: The gas-fired fuel heaters are subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units specified in Subpart Dc of 40 CFR 60. The units are subject to the record keeping and reporting requirements of this regulation, which are summarized in Appendix Dc of this permit. [Rule 62-204.800(7), F.A.C.; 40 CFR 60, Subpart Dc]

EQUIPMENT

2. Gas-Fired Fuel Heaters: The permittee is authorized to install two new 22 MMBtu per hour (LHV) fuel heaters. *{Permitting Note: The two new units will be added to two existing units under EU 013. The gas-fired fuel heaters heat the natural gas prior to firing in the "hot nozzle" dry low NOx combustors to increase cycle efficiency. The fuel heaters operate continuously during simple cycle operation and for startup to combined cycle operation. Once combined cycle operation is established, the fuel heaters are shut down and a small heat exchanger in the HRSG exhaust is used to preheat the natural gas prior to combustion in the gas turbines.}* [Application; Design]

PERFORMANCE REQUIREMENTS

3. Permitted Capacity: Based on the lower heating value (LHV) of natural gas, each gas-fired fuel heater shall not exceed 22 MMBtu per hour. [Application; Rule 62-210.200(PTE), F.A.C.]

4. Authorized Fuel: Each fuel heater shall fire only natural gas, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. [Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

5. Visible Emissions: Visible emissions from each gas-fired fuel heater shall not exceed 10% opacity (6-minute block average) except for one 6-minute block average, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

TESTING, RECORDS, AND REPORTING

6. Fuel Consumption: Equipment shall be installed and maintained to monitor the consumption of natural gas for each fuel heater. The monitoring system shall be capable of totaling the daily natural gas consumption. Natural gas consumption shall be reported in the Annual Operating Report. [40 CFR 60, Subpart Dc; Rule 62-210.370(2), F.A.C.

7. Fuel Sulfur: 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, D3246-81 or more recent versions. [Rule 62-4.070(3), F.A.C.]

8. Visible Emissions Tests: To determine compliance with the visible emissions standard, the permittee shall conduct testing in accordance with EPA Method 9. Initial compliance tests shall be conducted within 60 days of initial startup. Annual tests shall be conducted during each federal fiscal year. The permittee shall notify the Compliance Authority of scheduled tests at least 15 days in advance. Test results shall be submitted to the Compliance Authority within 45 days of conducting the tests. [40 CFR 60, Appendix A; Rules 62-204.800(7), 62-297.310(7)(a)9, 62-297.310(8)(c), F.A.C.]

C. COOLING TOWER

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

ID	Emission Unit Description
020	18-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: The cooling tower shall be designed, operated, and maintained to reduce the drift rate to no more than 0.001 percent of the circulating water flow rate. *{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 34 tons of PM per year and less than 10 tons of PM_{10} per year. Actual emissions are expected be less than half these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

SECTION IV. APPENDICES

CONTENTS

CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

(119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.

(179) Malfunction - 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.

(258) Shutdown - The cessation of the operation of an emissions unit for any purpose.

(275) Startup - 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.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

OVERVIEW

The project added an 1150 MW "4-on-1" combined cycle gas turbine system to the existing FPL Martin Power Plant. PSD-significant emissions increases required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC).

BACT CONTROL TECHNOLOGIES

The Department reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" issued the draft permit package. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

<u>BACT for CO and VOC Emissions</u>

Good Combustion and Operating Practices: BACT for CO and VOC emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. General Electric's dual-fuel combustors have demonstrated very low CO and VOC emissions while simultaneously reducing NOx emissions for gas and oil firing.

<u>BACT for NOx Emissions</u>

DLN Combustion: When firing natural gas under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dry low-NOx (DLN) combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in NOx emissions less than 9 ppmvd when firing natural gas. The Speedtronic™ control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

Wet Injection: When firing distillate oil under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dual-fuel combustor with wet injection designed to reduce the flame temperature and lower NOx emissions.

SCR: When firing natural gas or distillate oil in combined cycle mode, BACT for NOx emissions is the operation of the selective catalytic reduction (SCR) system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the HRSG, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. A properly designed SCR system will achieve at least 72% reduction with an ammonia slip of no more than 5 ppmvd.

<u>BACT for PM, SAM, and SO_2 Emissions</u>

Clean Fuels: BACT for PM, SAM, and SO_2 emissions is the use of natural gas as the primary fuel (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil (≤ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

BACT STANDARDS

The following summarizes the final Best Available Control Technology determinations for this project in accordance with Rule 62-212.400(BACT), F.A.C.

<u>Gas-Fired Fuel Heaters</u>: BACT for emissions of CO, NOx, PM/PM10, SAM, SO2, and VOC from the gas-fired fuel heaters is the efficient combustion of natural gas and a visible emissions standard of 10% opacity except for one 6-minute period not to exceed 20% opacity as determined by EPA Method 9.

<u>Cooling Tower</u>: BACT for emissions of PM/PM10 from the cooling tower is a design drift rate of no more than 0.001 percent of the circulating water flow rate.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Gas Turbines/HRSG Systems

Pollutant	Fuel	Method of Operation	Initial		CEMS
			ppmvd @ 15% O2	lb/hour	ppmvd @ 15% O2
CO [a]	Oil	Simple or Combined Cycle	14.4, 3-hr	64.7	15.0, 24-hr
	Gas	Simple or Combined Cycle	7.4, 3-hr	27.5	8.0, 24-hr
		Combined Cycle w/DB	7.4, 3-hr	37.5	8.0, 24-hr
		Simple or Combined Cycle w/PA	12.0, 3-hr	45.0	12.0, 24-hr
		Combined Cycle w/DB+PA	12.0, 3-hr	55.6	12.0, 24-hr
NOx [b]	Oil	Simple Cycle	42.0, 3-hr	319.2	42.0, 3-hr
		Combined Cycle – SCR	10.0, 3-hr	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0, 3-hr	58.7	9.0, 24-hr
		Simple Cycle w/PA	NA	(76.2)	12.0, 1-hr
		Simple Cycle w/Peaking	NA	(101.3)	15.0, 1-hr
		Combined Cycle – SCR	2.5, 3-hr	16.3	2.5, 24-hr
		Combined Cycle w/DB – SCR	2.5, 3-hr	22.1	2.5, 24-hr
PM/PM10 [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute average as determined by EPA Method 9 observations.		
SAM/SO2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5, 3-hr	6.0	NA
	Gas	Simple or Combined Cycle	1.3, 3-hr	2.8	NA
		Combined Cycle, w/DB or PA	4.0, 3-hr	9.2	NA
Ammonia [f]	Oil/Gas	Combined Cycle – SCR	5.0, 3-hr	NA	NA

FINAL BACT DETERMINATIONS

As summarized above, the Department determines that the standards specified in this permit represent the Best Available Control Technology (BACT) for emissions of CO, NOx, PM, SAM, SO_2, and VOC. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

Determination By:
(DRAFT)

J. F. Koerner, P.E., Project Engineer
New Source Review Section

Recommended By:
(DRAFT)

C. H. Fancy, Chief
Bureau of Air Regulation

Approved By:
(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The duct burners in the heat recovery steam generators (HRSGs) are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards 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), and 40 CFR 60.19 (General Notification and Reporting Requirements).

NSPS SUBPART Da REQUIREMENTS

The duct burners in the heat recovery steam generators (HRSGs) shall comply with the following federal requirements of 40 CFR 60, Subpart Da.

§ 60.40a Applicability and designation of affected facility.
§ 60.41a Definitions.
§ 60.42a Standard for particulate matter.
§ 60.43a Standard for sulfur dioxide.
§ 60.44a Standard for nitrogen oxides.
§ 60.46a Compliance provisions.
§ 60.47a Emission monitoring.
§ 60.48a Compliance determination procedures and methods.
§ 60.49a Reporting requirements.

Permitting Notes:

- *The duct burners have a heat input greater than 250 MMBtu per hour and are subject to NSPS Subpart Da.*
- *Particulate matter emissions are limited to 0.03 lb/million Btu heat input derived from the combustion of gaseous fuel. The exclusive firing of natural gas is expected to result in particulate matter emissions of less than 0.008 lb/MMBtu.*
- *Sulfur dioxide emissions are limited to 0.20 lb/million Btu heat input based on 100 percent of the potential combustion concentration (zero percent reduction). The exclusive firing of natural gas is expected to result in sulfur dioxide emissions of less than 0.005 lb/MMBtu.*
- *Nitrogen oxide emissions are limited to 1.6 pounds per megawatt-hour (gross energy output) as provided under § 60.46a(k)(1). Compliance with the emissions limit is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests. The combined gas turbine and duct burner emissions readily comply with this standard.*

NSPS SUBPART Dc REQUIREMENTS FOR GAS-FIRED FUEL HEATERS

The following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.

ID	Emission Unit Description
013	Four gas-fired fuel heaters

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards 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), and 40 CFR 60.19 (General Notification and Reporting Requirements).

NSPS SUBPART Dc REQUIREMENTS

The gas-fired fuel heaters shall comply with the following federal requirements of 40 CFR 60, Subpart Dc.

§ 60.40c Applicability and delegation of authority.
§ 60.41c Definitions.
§ 60.42c Standard for sulfur dioxide.
§ 60.43c Standard for particulate matter.
§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.
§ 60.45c Compliance and performance test methods and procedures for particulate matter.
§ 60.46c Emission monitoring for sulfur dioxide
§ 60.47c Emission monitoring for particulate matter.
§ 60.48c Reporting and record keeping requirements.

Permitting Notes:

- *NSPS Subpart Dc defines steam generating unit to mean, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." Because the fuel heaters have a heat input of 22 MMBtu per hour each and heat natural gas prior to combustion in the gas turbines, the units are subject to NSPS Subpart Dc.*
- *Because the fuel heaters fire only natural gas, these units are subject only to notification, record keeping, and reporting requirements. The Department believes that the specific conditions of the permit are sufficient to demonstrate compliance with NSPS Subpart Dc.*

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); and
    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C. The specific federal requirements are not listed, but can be obtained from the Department upon request.

ID	Emission Unit Description
011	Unit 8A Gas Turbine (170 MW) with Heat Recovery Steam Generator
012	Unit 8B Gas Turbine (170 MW) with Heat Recovery Steam Generator
017	Unit 8C Gas Turbine (170 MW) with Heat Recovery Steam Generator
018	Unit 8D Gas Turbine (170 MW) with Heat Recovery Steam Generator

NSPS GENERAL PROVISIONS

The emissions units are subject to the applicable General Provisions of the New Source Performance Standards 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), and 40 CFR 60.19 (General Notification and Reporting Requirements).

NSPS SUBPART GG REQUIREMENTS

The gas turbines shall comply with the following federal requirements.

§ 60.330 Applicability and designation of affected facility.
§ 60.331 Definitions.
§ 60.332 Standard for Nitrogen Oxides.
§ 60.333 Standard for Sulfur Dioxide.
§ 60.334 Monitoring of Operations.
§ 60.335 Test Methods and Procedures.

Permitting Notes:

- *Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NOx emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. The emissions standards of the PSD permit are more stringent than this requirement. When firing natural gas, the "F" value (NOx allowance for fuel bound nitrogen shall be assumed to be 0. See EPA's March 12, 1993 determination regarding the use of NOx CEMS.*
- *The gas turbine is limited to firing any fuel that contains sulfur in excess of 0.8 percent by weight.*
- *The requirement to monitor the nitrogen content of natural gas fired is waived. A NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. This is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *The permit contains a custom monitoring schedule for determining the sulfur content of fuels that is sufficient to demonstrate compliance with the NSPS limit. It is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *Emissions in excess of the NSPS standard for nitrogen oxides shall be determined on 1-hour basis. The continuous compliance demonstration by NOx CEM system data shall substitute for the NSPS requirements regarding the water-to-fuel ration. NOx CEM system data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit. As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum*

of four data points for each hour and calculate an hourly average. The requirements for the CEM systems specified by the specific conditions of this permit satisfy these requirements.}

- *Emissions in excess of the NSPS standard for sulfur dioxide shall be determined on a daily basis. However, the frequency specified in the custom fuel monitoring schedule is sufficient to demonstrate compliance with the with the NSPS limit. It is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.*
- *The permittee is required to submit a semiannual report of emission in excess of the NSPS standards as required by 40 CFR 60.7, Subpart A, General Provisions.*
- *The Department may request that NOx emission data also be presented in terms of the NSPS standard (NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent). The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator. This is consistent with guidance from EPA Region 4.*
- *The permittee is allowed to conduct initial performance tests at a single load because the permit requires demonstration of continuous compliance with the NOx BACT standards. This is consistent with guidance from EPA Region 4.*
- *The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in the NSPS requirements. Flow rate data shall be obtained to calculate mass emission rates. These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.*
- *The permit species sulfur testing methods and allows the permittee to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content. These requirements allow different methods than provided by the NSPS requirements, but are equally stringent and will ensure compliance with this rule.*
- *The fuel analysis requirements of the permit meet or exceed the NSPS requirements and ensure compliance.*

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.

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.]

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

FPL Martin Power Plant
Project No. 0850001-010-AC
Air Permit No. PSD-FL-327

PROJECT DESCRIPTION

The applicant proposes to construct a "4-on-1" 1150 MW combined cycle Unit 8 consisting of the following equipment and specifications: two existing 170 MW simple cycle gas turbine-electrical generator sets (8A and 8B), two new 170 MW gas turbine-electrical generator sets (8C and 8D), four gas-fired heat recovery steam generators (495 MMBtu/hour, LHV), a common steam-electrical generator (470 MW), two new gas-fired fuel heaters (22 MMBtu/hour, each), a cooling tower, and other associated support equipment. Each gas turbine will fire natural gas as the primary fuel and very low sulfur distillate oil as a restricted alternate fuel (≤ 500 hours/year). Each gas turbine may operate in simple cycle mode for 3390 hours per year while the combined cycle components are being constructed. Once combined cycle operation is established, simple cycle operation is limited to an average of 1000 hours per year. Additional equipment includes four 120-foot stacks combined cycle stacks, four 80-foot simple cycle stacks, and an aqueous ammonia storage tank.

CO, PM/PM_{10}, and VOC will be minimized by the efficient, high-temperature combustion of natural gas and distillate oil. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of very low sulfur distillate oil. NOx emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NOx controls, a selective catalytic reduction (SCR) system further reduces NOx emissions during combined cycle operation. These controls are determined to represent the Best Available Control Technology (BACT). The following limited alternate methods of operation are allowed: duct burning (DB, 2880 hours per year), power augmentation (PA, 400 hours/year), and peaking (60 hour/year for simple cycle and 400 hours/year for combined cycle). The draft permit includes the following standards for emissions of CO, NOx, VOC, and ammonia.

Pollutant	Fuel	Method of Operation	ppmvd @ 15% O_2	Compliance
CO	Oil	Simple or Combined Cycle	15.0, 24-hr	CEMS
	Gas	Simple or Combined Cycle	8.0, 24-hr	CEMS
		Simple or Combined Cycle w/PA	12.0, 24-hr	CEMS
NOx	Oil	Simple Cycle	42.0, 3-hr	CEMS
		Combined Cycle – SCR	10.0, 24-hr	CEMS
	Gas	Simple Cycle	9.0, 24-hr	CEMS
		Simple Cycle w/PA	12.0, 1-hr	CEMS
		Simple Cycle w/Peaking	15.0, 1-hr	CEMS
		Combined Cycle – SCR	2.5, 24-hr	CEMS
VOC	Oil	Simple or Combined Cycle	2.5, 3-hr	Test
	Gas	Simple or Combined Cycle	1.3, 3-hr	Test
		Combined Cycle	4.0, 3-hr	Test
Ammonia	Oil/Gas	Combined Cycle	5.0, 3-hr	Test

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, meteorological, and geological features).*

Jeffery J. Koerner 7-30-02

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief, BAR

THROUGH: Al Linero, Administrator - New Source Review Section

FROM: Jeff Koerner, New Source Review Section JK

DATE: July 30, 2002

SUBJECT: FPL Martin Power Plant
Project No. 0850001-010-AC
PSD Permit No. 327
Unit 8 - New 1150 MW "4-on-1" Combined Cycle Gas Turbine

Attached for your review are the following items:

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

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, rule applicability, BACT determinations and permit conditions. The P.E. certification briefly summarizes the proposed project. The project is subject to power plant siting. Day #90 is August 4, 2002. I recommend your approval of the attached Draft Permit for this project.

CHF/AAL/jfk

Attachments