Florida Department of Environmental Protection

Memorandum

TO: ~~Clair Fancy~~ by adg

THRU: Al Linero Al Linero 7/22

FROM: Teresa Heron TH.

DATE: July 22, 2002

SUBJECT: FPL Manatee Power Plant Unit 3
1150 Megawatt Gas-fueled Combined Cycle Project
DEP File No. 0810010-006-AC (PSD-FL-328)

Attached is the public notice package for construction of a 1150 MW gas-fueled power project at the existing FP&L Manatee Power Plant in Parrish, Manatee County. The project will consist of four combined cycle units with supplementally-fired heat recovery steam generators and a single large steam electrical generator. Ancillary facilities include inlet air chillers, four gas-fired heaters, an aqueous ammonia storage tank, four 120-foot stacks and four 80-foot (bypass) stacks.

Nitrogen Oxides (NO_X) emissions from each gas turbine will be controlled by Dry Low NO_X (DLN-2.6) combustion. The applicant proposed an NO_X emission limit of 2.5 (combined cycle operation mode) and 9 ppmvd (simple cycle operation mode) @15% O_2. The NO_X BACT standard has been determined to be 2.5 ppmvd @15% O_2 in a 24-hr average time. The units will run in the simple cycle mode for 3390 hours per year during the first year of operation while construction continues on the steam cycle. The simple cycle operation of these units is limited to 1,000 hour per year per unit after the first year.

The turbines will burn natural gas only. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas and the design of the GE unit. Although higher pollutant concentrations are claimed during several high power modes, we found from reviewing data from Gulf Power that these are only significant for CO from power augmentation. We did not see higher concentrations during duct firing, but allowed higher levels for VOC emissions.

Maximum predicted air quality impacts due to emissions from the FPL project are less than the applicable PSD Class II significant impact levels, with the exception of 24-hour average PM_{10}. Therefore, multi-source modeling was required for PM_{10}. The modeling showed that the available increment has not been consumed. The Fish and Wildlife Service reviewed the refined modeling performed by the applicant for the Class I Chassahowitzka National Park. They advised by a letter on April 4 that they anticipate no adverse impacts on air quality related values.

We have not yet received input from EPA. They may comment during the 30-day comment period. As you know, we are issuing this action under delegated authority as well as under our rules.

We reviewed this project in accordance with the schedule established by the Power Plant Siting Office. Our draft package is due to them in mid-August for preparation of the staff report. In the meantime we can issue the draft permit, as the application is complete for the purposes of PSD. We recommend your approval of the attached Intent to Issue.

AAL/th

Attachments

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 24, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Paul Plotkin, Plant General Manager
Florida Power and Light Company
700 Universe Boulevard
June Beach, Florida 33408

Re: DEP File No. 0810010-006-AC (PSD-FL-328)
FPL Manatee Power Plant
1150-Megawatt Combined Cycle Power Project

Dear Mr. Plotkin:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the FPL Manatee Unit 3 Combined Cycle Project to be located in Parrish, Manatee County. The Department's Intent to Issue Air Construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

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 7 (seven) 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 A. A. Linero, P.E. Administrator, New Source Review Section at the above letterhead address. If you have any questions please call Ms. Teresa Heron at 850/921-9529 or Mr. Linero at 850/921-9523.

Sincerely,

A. A. Linero P.E.

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

CHF/th

Enclosures

In the Matter of an
Application for Permit by:

Mr. Paul Plotkin, Manatee Plant General Manager
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

DEP File No. PSD-FL-328
FP&L Manatee Power Plant Unit 3
Manatee County

_______________________________/

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, 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, applied on February 22, 2002 to the Department for a PSD permit for a 1150-megawatt natural gas-fueled combined cycle project (Unit 3) at the FP&L Manatee Power Plant in Parrish, Manatee County.

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 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 Public Notice of Intent to Issue PSD Permit. 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 Public Notice. 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.

AA Linero
for 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 7/24/02 to the person(s) listed:

Paul Plotkin, FPL*
K. H. Simmons, FPL
Gregg Worley, EPA
John Bunyak, NPS
Jerry Kissell, DEP SWD
Ken Kosky, P.E., Golder Associates
Chair, Manatee County BCC*
Buck Oven

Karen Collins-Fleming, PhD., Manatee County EMD
Jerry Campbell, Hillsborough County EPC
Peter Hessling, Pinellas County DEM
Clarence Troxell*
Manatee Citizens Against Pollution*
ManaSota 88*

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 24, 2002
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-328

FP&L Manatee Power Plant Unit 3
Manatee 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 Florida Power and Light Company. The permit is one of several authorizations needed to construct a nominal 1150-megawatt (MW) natural gas-fueled power project at the FP&L Manatee Power Plant at 19050 S.R. 62 in Parrish, Manatee County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), sulfuric acid mist (SAM), volatile organic compounds (VOC), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are Florida Power and Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

FP&L proposes to construct a gas-fueled unit (Unit 3) consisting of: four nominal 170-MW General Electric PG7241FA combustion turbine-electrical generators, four supplementally-fired heat recovery steam generators (HRSG), and a single large steam turbine-electrical generator. The units will run in the simple cycle mode for 3390 hours per year during the first year of operation while construction continues on the steam cycle. The simple cycle operation of these units will be limited to 1,000 hours per year per unit after the first year. Additional equipment includes four 120-foot stacks, and four 80-foot bypass stacks; four natural gas fired heaters, and an aqueous ammonia storage tank.

During simple cycle operation, NO_X emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors and must meet an emission limit of 9 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2). During very limited (460 hours per year) periods of simple cycle power (steam) augmentation and peaking, NO_X emissions will be limited to 12 and 15 ppmvd @15% O_2. NO_x emissions during the predominant combined cycle operation mode will be further controlled by selective catalytic reduction (SCR) to achieve 2.5 pppmvd at 15% O_2.

Emissions of CO will be controlled to 8 ppmvd @15% O_2 on a 24-hour block average. The 24-hour block averages may be adjusted for emissions of 12 ppmvd @15% O_2 during limited periods of power augmentation.

Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas. Ammonia emissions (NH_3) generated due to NO_X control on the combined cycle unit will be limited to 5 ppmvd.

According to FP&L, the combined maximum emissions from the four combined cycle sets (including emissions from heaters) that comprise Unit 3 are summarized below. Some will be less because of the BACT determination.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	224	25/15
CO	749	100
NO_X	411	40
VOC	99	40
SO_2	189	40
Sulfuric Acid Mist	20.6	7

According to the applicant, maximum predicted air quality impacts due to emissions from the FPL project are less than the applicable PSD Class II significant impact levels, with the exception of 24-Hour PM_{10} Therefore, multi-source modeling was required for 24-Hour PM_{10}. The predicted impacts in the Chassahowitzka NWR are less than the applicable PSD Class I significant impact levels; therefore, multi-source Class I PSD increment modeling was not required. The maximum predicted PSD Class II 24-Hour PM_{10} increments consumed in the vicinity of FPL Manatee by all increment consuming sources (since 1975-77) in the area will be as follows:

Averaging Time	Increment Consumed All Sources/FPL Project (ug PM_{10}/m^3)	Allowable Increment All Sources (ug PM_{10}/m^3)	Percent Increment Consumed All Sources/FPL Project (percent)
24-hour	14/7	30	47/23

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.

Notice for Newspaper

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 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. Mediation is not available in this proceeding.

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.

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
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Manager, 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

AND

PRELIMINARY DETERMINATION

Florida Power and Light Company
FP&L Manatee Power Plant

1150-Megawatt Combined Cycle Power Project

Manatee County

DEP File No. 0810010-006-AC (PSD-FL-328)

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

July 24, 2002

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Florida Power and Light Company, Manatee Plant
19050 State Road 62
Parrish, Florida 34219

Authorized Representative: *Paul Plotkin, General Manager*

1.2 Reviewing and Process Schedule

02-22-02: Date of Receipt of Application
06-10-02: Application Complete
07-23-02: Distributed Intent to Issue

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The FP&L Manatee Power Plant is located in Manatee County. The location is approximately 115 km to the south of the Chassahowitzka National Wilderness Area (CNWA). The proposed site is at 19050 State Road 62 in Parrish, Manatee County. The UTM coordinates for this facility are Zone 17; 367.25 km East; 3,054.15 km North.

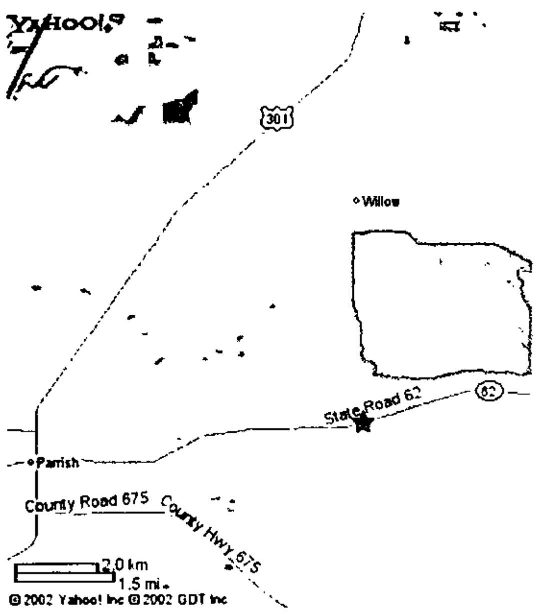

Figure 1 – Proposed Project Site

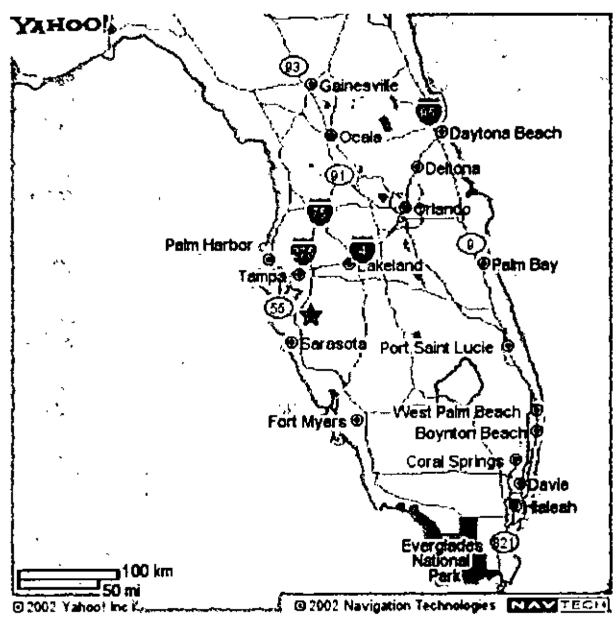

Figure 2 – Regional Location

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

This existing facility consists of two 800-megawatt fossil fuel steam generators that primarily burn 1 percent sulfur residual fuel oil. Each unit discharges through a separate 499-foot stack. Unit 1 began commercial operation in 1976 and Unit 2 began commercial operation in 1977. The units may use No. 6 and No. 2 fuel oil, propane, and used oil from FPL operations. The Department recently issued an Intent to permit the use of natural gas in Units 1 and 2. This facility also includes the following unregulated/insignificant sources: the emergency diesel generator; miscellaneous mobile equipment and internal combustion engines; painting of plant equipment; and non-halogenated solvent cleaning operations.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY. This facility is also a Major Facility on the basis of inclusion in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and emissions greater than 100 TPY for several criteria pollutants. The existing facility is classified as a Major Source of hazardous air pollutants (HAP) because emissions of hydrogen chloride exceed 10 tons per year.

The proposed project (Unit 3) will generate 1,150 megawatts (nominal MW) of electrical power. Because the proposed emissions from the new unit are greater than 40 TPY for at least one criteria pollutant, the project is considered a major facility modification with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), and a Best Available Control Technology (BACT) determination is required. Given that emissions of at least one single criteria pollutant already exceed 100 TPY at the facility, PSD Review and a BACT determination are required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. These values are: 40 TPY for NO_X, SO_2, and VOC; 25/15 TPY of PM/PM_{10}; 7 TPY of Sulfuric Acid Mist (SAM); and 100 TPY of CO. Projected emissions of HAPs from the proposed project (Unit 3) will be below the thresholds that require a case-by-case Maximum Achievable Control Technology (MACT) determination.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

ID	Emission Unit Description
005	**Combined Cycle Unit No. CC-3A** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MMBTU/hr (LHV) natural gas fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and an 80-foot bypass stack. This unit will also operate in simple cycle and high power modes.
006	**Combined Cycle Unit No. CC-3B** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MMBTU/hr (LHV) natural gas fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and an 80-foot bypass stack. This unit will also operate in simple cycle and high power modes.

007	**Combined Cycle Unit No. CC-3C** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MMBTU/hr (LHV) natural gas fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and an 80-foot bypass stack. This unit will also operate on simple cycle and high power modes.
008	**Combined Cycle Unit No. CC-3B** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MMBTU/hr (LHV) natural gas fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and an 80-foot bypass stack. This unit will also operate in simple cycle and high power modes.
009	**Combined Cycle Unit No. CC-3D** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MMBTU/hr (LHV) natural gas fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and an 80-foot bypass stack. This unit will also operate in simple cycle and high power modes.
010	**Other Emissions Units** including four gas heaters and an aqueous ammonia storage tank.

Significant emission rate increases per Table 212.400-2, F.A.C. will occur for CO, VOC, SO_2, Sulfuric Acid Mist (SAM), PM/PM_{10} and NO_X. A BACT determination is required for each of these pollutants. An air quality impact review is also required for CO, VOC, PM/PM_{10}, NO_X, Sulfuric Acid Mist (SAM) and SO_2

Each turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors and evaporative inlet cooling systems. NO_x emissions from the combined cycle unit will be further controlled by selective catalytic reduction (SCR). Each will have a maximum heat input rating of approximately 1,600 mmBtu per hour at 59 degrees Fahrenheit (°F) while operating at 100% load.

Each gas turbine will initially be constructed and operated in simple cycle mode and intermittent duty for 3390 hrs/yr during the first year of operation (while construction continues on the steam cycle). Thereafter, each gas turbine will continuously operate in the combined cycle mode, but may operate in simple cycle mode for no more than an average fuel equivalent of 1000 hrs during any 12-month period. Each turbine may also operate 400 hrs/year in power (steam) augmentation mode, 60 hrs/year in peaking mode and 2280 hrs/yr in supplemental gas firing (duct burning) mode.

The key components of the GE MS 7001FA (a predecessor of the PG 7241FA) are identified in Figure 3. An exterior view is also shown. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

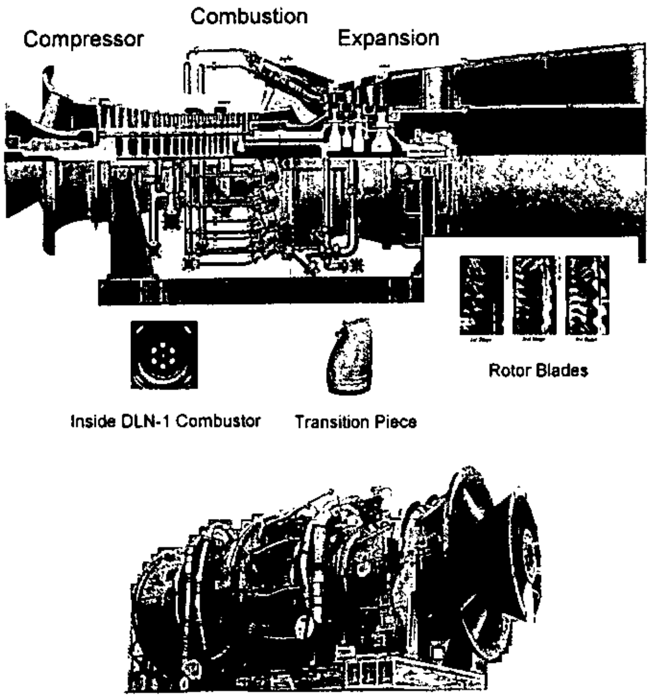

Figure 3 - Internal and External Views of Early GE 7FA

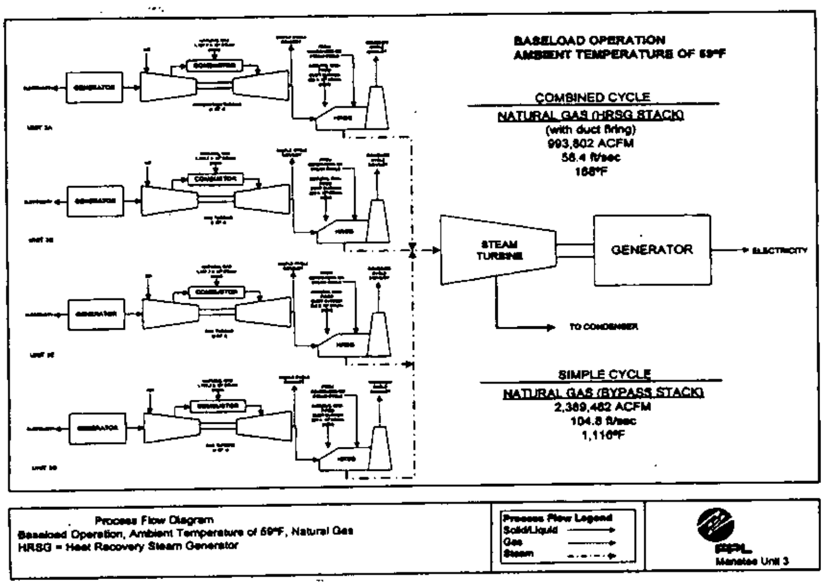

Figure 4 – Process Flow Diagram

4. PROCESS DESCRIPTION

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

Flame temperatures in a typical combustor section can reach 3600 °F. Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

Figure 4 is a simplified process flow diagram of the proposed FPL project. The units will operate in the simple cycle mode during the first year and during limited periods of time thereafter. Cycle efficiency (defined as a percentage of useful shaft energy output to fuel energy input) is approximately 35 percent for F-Class combustion turbines in the simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

All units will ultimately operate in combined cycle mode in which the combustion turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator. The steam, in-turn, drives a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet air density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an inlet air cooler (fogger or chiller) can be installed ahead of the combustion turbine inlet. At an ambient temperature of 95 °F, roughly 15 MW of power can be regained per simple cycle unit by using a chiller to cool the inlet air to 50 °F.

Each unit will include an evaporative cooling system (fogger) ahead of the compressor and a 495 MMBtu/hr (LHV) gas-fired duct burner between the combustion turbine and the HRSG. *Power augmentation* is accomplished by injecting some steam from the HRSG into the rotor (power) section of the combustion turbine. *Peaking* is simply running the unit at greater than design fuel input for short periods of time. The additional process information related to the combustor design, and control measures to minimize pollutant emissions are given in the attached draft BACT determination.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21.

This project will be located in Manatee County; an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to PSD review under Rule 62-212.400, F.A.C. for the reasons given in Section 2.3, Facility Category, above.

This PSD review consists of an evaluation of resulting ambient air pollutant concentrations and increases with respect to the National Ambient Air Quality Standards and PSD Increments as well as a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO, VOC, SO_2, SAM and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth

The emission units affected by this air construction permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules related to air:

5.1 State Regulations

Chapter 62-4	Permits.
Chapter 62-17	Electrical Power Plant Siting
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration of Air Quality
40 CFR 60	Applicable sections of Subpart A, General Requirements, Subparts Da, Dc, and GG
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

5.2 Manatee County Code of Ordinances

Chapter 1-32	Air Pollution Control
Section 1-32-3	Adoption of State Rules
Section 1-32.5(d)	Prohibitions (fuel sulfur limit)
Section 1-32.6	Permits Required
Section 1-32.7	Prevention of Significant Deterioration

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2, F.A.C.): PM/PM_{10}, SO_2, NO_X, CO, VOC and SAM, and negligible quantities of fluorides (F), mercury (Hg) and lead (Pb). The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions are summarized in the Draft BACT document and the Specific Condition Nos. 11, Section III of Draft Permit PSD-FL-328.

6.2 Emission Summary

Maximum annual emissions increases for all PSD pollutants due to the project are presented below:

PROJECT EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Emissions [1]	Emissions [2]	PSD Significance	PSD Review?
PM/PM_{10} (filterable)	61	224	25	Yes
SO_2	66	189	40	Yes
NO_X	403	411	40	Yes
CO	189	749	100	Yes
Ozone (VOC)	19	99	40	Yes
Sulfuric Acid Mist	7	21	7	Yes
Total Fluorides	NEG	NEG	3	No
Mercury	0	0	0.1	No
Lead	0	0	0.6	No
HAPs	4	13	NA	NA

1. First year of operation maximum emissions are based on 3,330 hours of simple cycle operation at 100 percent load and 60 hours of simple cycle operation at high power modes (power augmentation or peaking). Hours of operation are average per combustion turbine.
2. After first year of operation maximum emissions are sum of emissions from:
4,480 hours of combined cycle operation at 100 percent load; 2,880 hours of combined cycle operation at 100 percent load with duct burners;
400 hours – of combined cycle operation at 100 percent load with duct burners and high power modes (power augmentation, peak mode); and
1000 hours - of Simple Cycle operation at 100 percent load, natural gas. Hours of operation are average per combustion turbine.

6.3 Control Technology

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may be potentially emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_X, SO_2, CO, VOC, SAM, and PM/PM_{10}. Emissions control will be accomplished primarily by good combustion of clean natural gas. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. A selective catalytic reduction (SCR) system will be installed within the heat recovery steam generator of the single combined cycle unit to effect additional NO_X control during combined cycle operation. A full discussion is given in the separate Draft Best Available Control Technology (BACT) Determination that is incorporated into this document by reference.

6.4 Existing Air Quality in the Vicinity of the project

6.4.1 Description of Vicinity

Refer to Figures 1 and 2 above. The project will be located on State Road 62 in Parrish, Manatee County. The site is several miles east of I-75 in Manatee County.

The Department recently approved two other power plant projects in Manatee County. These include a nominal 250-megawatt power plant (CPV Manatee) and a 600-megawatt power plant (El Paso Manatee). Both of the proposed facilities will be located near Piney Point, (U.S. 41, South of the Hillsborough/Manatee County line).

Refer to Figure 5. The immediate area is sparsely populated. The county seat is Bradenton, located about 14 miles southwest of Parrish. St. Petersburg in Pinellas County is about 20 miles northwest of Parrish across Tampa Bay. TECO Big Bend is by Apollo Beach approximately 14 miles North of the FPL Manatee site.

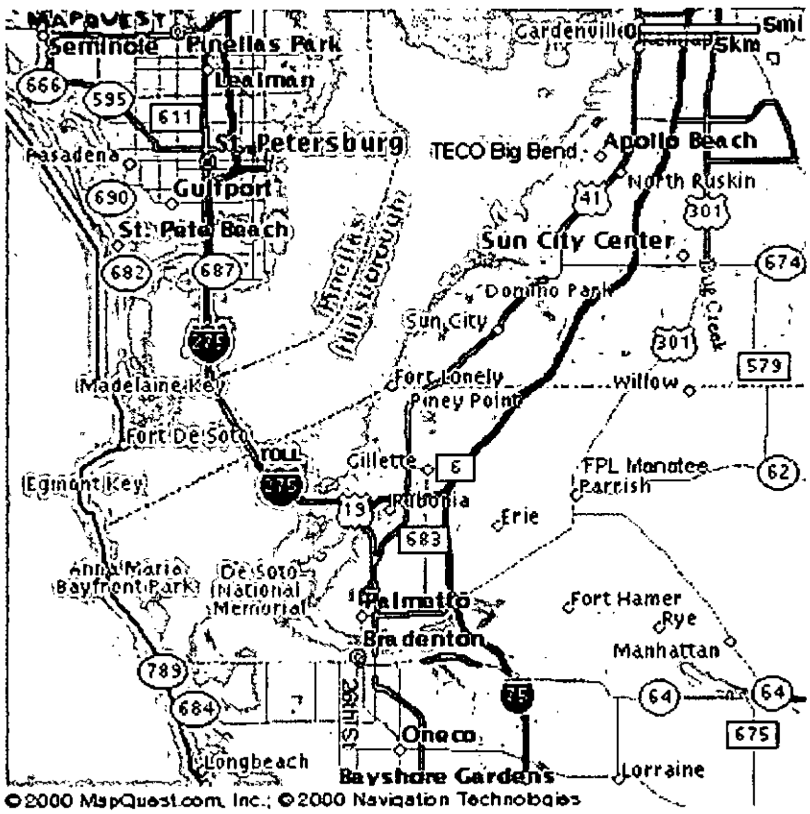

Figure 5 – Location of Project, Nearby Cities and Power Plants

The most immediate surrounding area (within 3 to 5 miles from the Manatee Plant) is rural but with various housing developments nearby. Farms and ranches border the plant site. Figure 6 is a photograph taken from the entrance to FPL Manatee, South of the plant. The photograph shows the two existing units. Figure 7 shows the entrance to the FPL Manatee facility. The site for the proposed unit, Figure 8, is to the west of the two existing units. The photograph shows some cows on the property. Figure 9 shows the rural surroundings. Figure 8 was also taken from the existing units in the direction of the proposed site. Figure 9 is a photograph taken from State Road 62 near the facility.

Figure 6 – FPL Manatee Power Plant

Figure 7 – Entrance to Manatee Power Plant

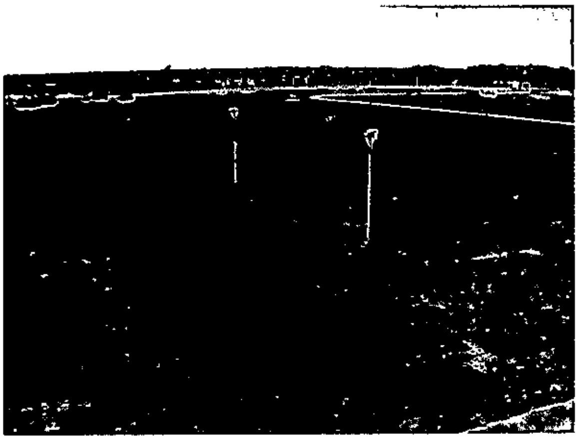

Figure 8 – Site for Proposed New Unit

Figure 9 – Area surrounding FPL Manatee

6.4.2 Climate

The average annual temperature for Manatee County is 72 degrees. Winds are predominately out of the East.

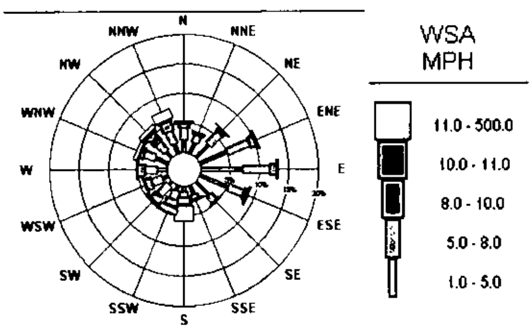

Figure 10 – Manatee County Wind Rose – January 1998 to December 1998

6.4.2 Major Stationary Sources in Manatee County

The current largest sources of air pollutants (stack emissions) in Manatee County are listed below:

MAJOR SOURCES OF SO_2 IN MANATEE COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Manatee Power Plant (Existing boilers)	26,351
Piney Point Phosphates (inactive)	Piney Point Phosphates	1.320*
Tropicana Products, Inc	Tropicana Products, Inc	256
Florida Power and Light	**Manatee Power Plant (Proposed turbines)**	**189***
CPV Gulfcoast, Ltd (permitted)	CPV Gulfcoast, Ltd	76*
El Paso (permitted)	Manatee Energy Center	69*

* Potential emissions

MAJOR SOURCES OF NO_X IN MANATEE COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Manatee Power Plant	8,134
Tropicana Products, Inc	Tropicana Products	653
Florida Power and Light	**Manatee Power Plant (Proposed turbines)**	**411***
El Paso (permitted)	Manatee Energy Center	365*
Piney Point Phosphates (inactive)	Piney Point Phosphates	169*
CPV Gulfcoast, Ltd (permitted)	CPV Gulfcoast, Ltd	126*

* Potential emissions

MAJOR SOURCES OF VOC IN MANATEE COUNTY (2000)

Owner/Company	Site Name	Tons per year
Tropicana Products, Inc	Tropicana Products, Inc	1,883
Manatee County Utility Dept	Lena Road Landfill	876
Florida Power and Light	Manatee Power Plant (Existing boilers)	132
Florida Power and Light	**Manatee Power Plant (Proposed turbines)**	**99***
American Marine Holdings, Inc	Donzi Marine	79
Flowers Baking Company	Flowers Baking Company	60
Chris Craft Boats	Chris Craft Boats	70
El Paso (permitted)	Manatee Energy Center	29*

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

MAJOR SOURCES OF PM IN MANATEE COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Manatee Power Plant (Existing boilers)	2,099
Florida Power and Light	**Manatee Power Plant (Proposed turbines)**	**224***
El Paso (permitted)	Manatee Energy Center	181*
Tropicana Products, Inc	Tropicana Products, Inc	153
CPV Gulfcoast, Ltd (permitted)	CPV Gulfcoast, Ltd	57*
Flowers Baking Company	Flowers Baking Company	3

* Potential emissions

MAJOR SOURCES OF CO IN MANATEE COUNTY (2000)

Owner/Company	Site Name	Tons per year
Florida Power and Light	Manatee Power Plant (Existing boilers)	16,720
Tropicana Products, Inc	Tropicana Products, Inc	1,975
Florida Power and Light	**Manatee Power Plant (Proposed turbines)**	**749***
El Paso (permitted)	Manatee Energy Center	349
CPV Gulfcoast, Ltd (permitted)	CPV Gulfcoast, Ltd	222
Apac Florida, Inc	Apac Florida	22

* Potential emissions

6.4.3 Air Quality Monitoring in Manatee County

Manatee County has 7 monitors at 4 sites measuring PM, ozone, SO_2 and NO_2. The 2001 Manatee County monitoring network is shown in Figure 11.

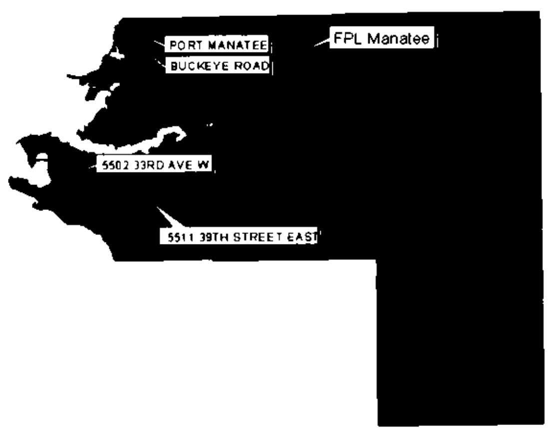

Figure 11 – Manatee County Monitoring Network

6.4.4 Ambient Air Quality in Manatee County

Measured ambient air quality is given in the following table. 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.

1999 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}	Buckeye Road	081-0008	17-3056.200N-348.100E	24-hour	48	42		150[C]	ug/m³
				Annual			24	50[b]	ug/m³
SO_2	Port Manatee	081-3002	17-3057.318N-347.461E	3-hour	60	56		500[a]	ppb
				24-hour	21	17		100[a]	ppb
				Annual			4	20[b]	ppb
NO_2	GT Bray	081-4012	17-3040.318N-340.060E	Annual			7	53[b]	ppb
CO	Tampa	057-1070	17-3096.500N-357.000E	1-hour	6	6		35[a]	ppm
				8-hour	4	3		9[a]	ppm
Ozone	Port Manatee	081-3002	17-3057.318N-347.461E	1-hour	0.112	0.111	0.051	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.
d – Mean ozone value reflects the average daily 1-hour maximum reading Jan.-Sept.99.

6.5 Air Quality Impact Analysis

6.5.1 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.

6.5.2 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 Class 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 PM_{10}) are less than the applicable "significant impact levels." These values are tabulated below and compared with existing ambient air quality measurements from the local ambient monitoring network.

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	0.3	1	~ 10	60	NO
	24-Hour	4	5	~ 55	260	NO
	3-Hour	18	25	~ 155	1300	NO
PM_{10}	Annual	0.5	1	~ 25	50	NO
	24-Hour	7	5	~ 50	150	YES
CO	8-Hour	60	500	~ 4500	10,000	NO
	1-Hour	140	2000	~ 7,000	40,000	NO
NO_2	Annual	0.8	1	~ 15	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective ambient air quality standards and the baseline concentrations in the area. They are also less than the respective significant impact levels (except for PM_{10}) that would otherwise require more detailed modeling efforts. In the case of PM_{10}, additional modeling was required and is detailed in Section 6.5.5 below.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA) located about 115 km to the north. 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" 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.

MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE FPL PROJECT COMPARED WITH PSD CLASS I SIGNIFICANT IMPACT LEVELS (CHASSAHOWITZKA)

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	0.04	0.3	NO
NO_2	Annual	0.002	0.1	NO
SO_2	Annual	0.001	0.1	NO
	24-hour	0.02	0.2	NO
	3-hour	0.1	1	NO

6.5.3 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 the table below, 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.

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	7	10	~ 50	NO
NO_2	Annual	1	14	~ 15	NO
SO_2	24-hour	4	13	~ 55	NO
CO	8-hour	60	575	~ 4500	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC. However, the pollutant associated with VOC is actually ozone. Projects exhibiting VOC emissions greater than 100 tons per year, such as the present project are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data.

Ozone is not directly emitted from stationary sources. Impacts of VOC emissions on ozone are usually not seen locally, but contribute to regional formation of ozone. The three regional ozone monitors in the area 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 Ambient Air Quality Standards (AAQS) and PSD increment analysis for 24-hour PM_{10} in the Class II area in the vicinity of the project;
- 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.

6.5.4 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 and output features. 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 the Tampa International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1991 through 1995. 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 if and when EPA revises 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 1990 ISCST3 data, which was enhanced for CALPUFF. Meteorological surface data used were from Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers and Orlando. Meteorological upper air data used were from Ruskin, Apalachicola and West Palm Beach. Hourly precipitation data were obtained from 27 stations around the central 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.

CALPUFF is also 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.

6.5.5 Multi-source AAQS PM_{10} 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 in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

AMBIENT AIR QUALITY IMPACTS

Pollutant	Averaging Time	Major Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
PM_{10}	24-hour	16	50	66	NO	150

6.5.6 Multi-source PSD Class Increment Analysis for PM_{10}

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 PM_{10} (the baseline year was 1975 for existing major sources of PM_{10}). The maximum predicted 24- hour PM_{10} PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of FPL Manatee are shown in the following table. The table shows that the maximum predicted impacts are less than the allowable Class II PM_{10} increments.

PSD CLASS II INCREMENT ANALYSIS

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Impact Greater Than Allowable Increment?	Allowable Increment ($\mu g/m^3$)
PM_{10}	24-hr	14	NO	30

6.5.7 Ozone Impact Assessment

FP&L provided additional information on July 19 to provide assurances that their emissions of VOC from Unit 3 will be less than 100 tons per year. Therefore modeling of impacts on ozone due to VOC emissions is not required. The main impact on ozone from stationary sources in the area is due to nitrogen oxides emissions (NO_X) rather than VOC. Furthermore, ozone formation occurs on a regional basis and includes the contributions of emissions from traffic, power plants throughout the region, VOC sources throughout the region, etc.

In contrast to SO_2 and PM_{10} modeling, the NO_X and VOC emitted from a specific source cannot be modeled to predict a nearby impact on ozone and this was not attempted in this review. The emissions from the project were not used as inputs in conjunction with a regional air quality model such as the Urban Airshed Model (UAM). It is very expensive to run such a model and the model results would not be sensitive to the relatively small inputs from the proposed project (411 TPY of NO_X and less than 100 TPY of VOC).

For comparison, a large reduction in regional NO_X emissions is expected (required) from certain power plants in the Tampa Bay Area on the order of 60,000 TPY of NO_X that will overwhelm any increase expected from the FP&L Manatee Unit 3 project. VOC emission decreases from mobile sources are also expected that will be more than an order of magnitude greater than the minimal emissions expected from the new unit. These decreases would make a much greater difference when considered in a model such as UAM, whereas impacts on ozone caused by emissions from Manatee Unit 3 would not be easy to discern.

Recently the Department issued a draft permit to FP&L to add natural gas capability at Manatee Units 1 and 2. These units together emitted roughly 9,300 TPY of NO_X in 2001 at the present 40 (plus) percent capacity factor. By comparison the two virtually identical units at FP&L's Martin Power Plant emitted approximately 6,300 tons of NO_X in 2001 with a fairly similar capacity factor.

The expectation is that the use of gas at the Manatee Power Plant Units 1 and 2 will result in a decrease in NO_X emissions to nearly the levels of the "sister" plant in Martin County. Due to construction of Unit 3 and the completion of numerous combined cycle projects under construction throughout the state, the capacity factor of FPL Manatee Units 1 and 2 will likely decline to approximately 25 percent by 2005-2006. Such a decline in capacity factor coupled with use of natural gas will result in greater NO_X reductions from Units 1 and 2 than increases from Unit 3.

The overall conclusions regarding ozone impacts are:

- The low emissions of VOC and highly controlled emissions of NO_X using selective catalytic reduction will minimize impacts on ground level ozone
- Favorable impacts from NO_X reductions at some large regional power plants will be much greater than any impacts from Manatee Unit 3.
- On-site reductions of NO_X due to gas use on Units 1 and 2 and greater competition from "clean units" such as Unit 3 will reduce NO_X emissions from the plant
- The proposed project will not hinder the overall trend in the region towards less NO_X emissions and lower impacts on ozone due to power plant construction and operation.

6.5.8 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas-fueled combustion 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 of PM_{10}, CO, NO_X, and SO_2 caused by the proposed project are less than the respective significant impact levels except for PM_{10}. The impacts on PM_{10} (including those of sources built since 1977, in turn, are less than the allowable PSD increments.

The concentrations of key pollutants are substantially less than values known to cause damage to vegetation. For example, sensitive vascular plants, such as legumes, blackberry, southern pine, red oak and ragweeds, are known to be sensitive to short term SO_2 exposure. Injury has been documented at exposures of 790 ug/m^3 according to the application.

Because natural gas contains such little sulfur, the average long-term and maximum short-term SO_2 concentrations caused by the proposed project in the vicinity of the facility are much lower (0.3 –18 ug/m^3) than the mentioned value. It is also noted that, at the site of the only SO_2 station in the county, the 3-hour average and 24-hour concentrations of SO_2 are 156 and 55 ug/m^3 respectively. Therefore, the contribution from the proposed project would be minimal. In the PSD Class I CNWA, the average long-term and maximum SO_2 short-term predicted concentrations are even less (0.001 to 0.1 ug/m^3) by at least two orders of magnitude.

The total maximum concentrations predicted to occur for NO_X from the FPL Manatee Unit 3 would be about 5 % of the existing NO_x concentrations in Manatee County, which is much less than the AAQS.

The impacts on ozone formation caused by NO_X and VOC emissions were discussed above. The project will not meaningfully contribute to ozone formation in the localized area. Any contribution to regional ozone formation will be more than compensated by the major reductions occurring at plants in Hillsborough County and the expected emission reductions from Manatee Units 1 and 2.

These low impacts from the mentioned pollutants are not expected to have any meaningful effect on the soils, vegetation and wildlife in the area. At the same time, improvements due to planned addition of natural gas to the fuel slate at Units 1 and 2 (at the same location) will tend to have a more than compensatory ameliorative effect on soils, vegetation, and wildlife.

Similar analyses apply to the other pollutants and their impacts on soil, vegetation and wildlife. The Department's conclusion is that the effects of the project on soils, vegetation, and wildlife will be minimal or insignificant locally, regionally, and at the Chassahowitzka National Wildlife Area.

Impact On Visibility and Regional Haze

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume visibility (typically zero percent opacity). The contribution to smog in the area will be minimal. The applicant submitted a regional haze analysis for the CNWA. It was reviewed by the Air Quality Branch at the U.S. Fish and Wildlife Service. Their conclusion regarding the modeling was that "the maximum impacts are well below the significant impacts levels for all increments" and "the maximum predicted impact in visibility, expressed as change in light extinction, was 0.64 percent, well below the recommended threshold of 5 percent." Therefore, the project will not have an adverse impact on the existing regional haze in the CNWA.

Clean and efficient gas-fueled combined cycle projects, such as this one, compete with existing conventional plants that emit much more sulfate and nitrate precursors that cause regional haze. Besides contributing little to regional haze, gas-fueled combined cycle projects also tend to help reduce regional haze by providing "cleaner" electricity than would otherwise be provided by the older conventional units.

Growth-Related Air Quality Impacts

According to the applicant, the existing commercial and industrial infrastructure should be adequate to provide any support services that the project might require. Construction will occur over a 24-month period requiring an average of 250 workers during that time. It is anticipate that many of these construction workers will commute to the site. There is an ample supply of skilled and semi-skilled workers in the general area that will likely provide much of the work force.

Major highways such as I-75, I-275, U.S. 41, and U.S. 301 can easily accommodate any additional regional traffic associated with the project. Locally, there will be short-term additional construction traffic on S.R. 62.

At build-out the plant will employ a total of 12 operational workers for Unit 3. This is an insignificant number of workers.

There are no adequate procedures under the PSD rules to fully assess all of the growth-related impacts. The project is also under simultaneous review through the Power Plant Siting process. The staff report is not yet complete, but it will likely address some of these topics in greater detail.

The proposed project is being constructed to meet current and future statewide electric demands. Obviously any increase in electric power capacity promotes or accommodates further statewide growth. However, the type of project proposed has the smallest overall physical "footprint," the least water requirements, the lowest capital costs, fewest labor requirements, and the lowest air emissions per unit of electric energy produced.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

The Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment.

In making this preliminary determination, the Department also drafted a determination of Best Available Control Technology that may be modified based on comments from the applicant, agencies, and the public.

Teresa Heron, Permit Engineer
Debbie Galbraith, Meteorologist
A. A. Linero, P.E. Administrator

PERMITTEE:

Florida Power and Light
700 Universe Boulevard
Parrish, Florida 34219

Authorized Representative:
Paul Plotkin, Plant General Manager

Facility Name: FPL Manatee Power Plant
Project No. 0810010-006-AC
Air Permit No. PSD-FL-328
Facility ID No. 0810010
SIC No. 4911
Expires: December 31, 2005

PROJECT AND LOCATION

This permit authorizes the construction of a new 1,150 megawatt gas-fueled combined cycle project (Unit 3) consisting of four nominal 170-megawatt (MW) General Electric PG 7241FA (GE 7FA) combustion turbine-electrical generators, four supplementally-fired heat recovery steam generators (HRSGs) each equipped with a 495 MMBtu/hr (LHV) natural gas fired duct burners, a 470 MW steam electrical generator, and associated equipment to be located at the existing FPL Power Plant facility at 19050 State Road 62 in Parrish, Manatee County. UTM coordinates are: Zone 17; 367.25 km East; 3054.15 km North.

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. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

FACILITY DESCRIPTION

The existing FPL Manatee Plant currently consists of two electrical generating units. Fossil fuel-fired steam electric generators, Unit No. 1 and Unit No. 2 (800 MW each), began operations in 1976 and 1977 respectively. The proposed new project is for the new electrical power Unit 3, which will generate a nominal 1,150 MW of electricity. The new Unit 3 will consist of four combined cycle gas turbines (680 MW, total) and one steam turbine/electric generator (470 MW, total) to`1 create a "4 on 1" combined cycle unit (1,150 MW). After completion of this project, the FPL Manatee Plant will have a nominal total generating capacity of 2,750 MW.

NEW EMISSIONS UNITS

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

ID	Emission Unit Description
006	**Combined Cycle Unit No. CC-3A** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MM Btu/hr natural gas (LHV) fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and a 80-foot bypass stack. This unit will also operate on simple cycle mode.
007	**Combined Cycle Unit No. CC-3B** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MM Btu/hr natural gas (LHV) fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and a 80-foot bypass stack. This unit will also operate on simple cycle mode.
008	**Combined Cycle Unit No. CC-3C** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MM Btu/hr natural gas (LHV) fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and a 80-foot bypass stack. This unit will also operate on simple cycle mode.
009	**Combined Cycle Unit No. CC-3D** consists of a natural gas-fueled General Electric Model PG7241FA (GE 7FA) combustion turbine-electrical generator with a nominal capacity of 170 MW, a 495 MM Btu/hr natural gas (LHV) fired heat recovery steam generator (HRSG), a single 470 MW steam turbine with associated electric generator (all four units connected), a 120-foot stack and a 80-foot bypass stack. This unit will also operate on simple cycle mode.
010	**Other Emissions Units** include four 24 MMBtu/hr (HHV) gas-fired fuel heaters and an aqueous ammonia storage tank.

REGULATORY CLASSIFICATION

Title III: Based on present Title V permit, the existing facility is a major source of hazardous air pollutants (HAP). Emissions of HAPs from the proposed project (Unit 3) are less than the thresholds that require a case-by-case Maximum Achievable Control Technology (MACT) determination.

Title IV: The new gas turbines are 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 facility is a Title V major source of air pollution in accordance with Chapter 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). A Title V Permit Revision will be required.

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 major facility of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality. The project requires a PSD permit.

NSPS: The new gas turbines are subject to the New Source Performance Standards of 40 CFR 60, Subpart GG. The heat recovery generators equipped with duct burner are subject to the New Source Performance Standards of 40 CFR 60, Subpart Da. The gas fired fuel heaters are subject to the New Source Performance Standards of 40 CFR 60, Subpart Dc.

NESHAP: No emission units are identified as being subject to a National Emissions Standards for Hazardous Air Pollutants (NESHAP).

SITING: The project is subject to Florida 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.

COMPLIANCE AUTHORITIES

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the DEP Southwest District Office, 3804 Coconut Palm Dr, Tampa, Florida 33619-8218. Copies of all such documents shall be submitted to the Air Section of the Manatee County Environmental Management Department, 202 Sixth Avenue East, Bradenton, Florida 34208.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix XS. Continuous Monitor Systems Semi-Annual Report

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 02/22/02 and all related completeness correspondence (06/12/02 and 06/22/2002)
- Draft permit package issued on 07/24/02
- Comments received from the public, the applicant, the EPA Region 4 Office, and the U.S. Fish and Wildlife Service.

SECTION II. ADMINISTRATIVE REQUIREMENTS (DRAFT)

1. General Conditions: The owner and operator are subject to, and 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. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if 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. [40 CFR 52.21(r)(2)]

4. Completion of Construction: The permit expiration date is December 31, 2005. Physical construction shall be completed by September 30, 2005. The additional time provides for testing, submittal of results, and submittal of the Title V permit application to the Department.

5. Permit Expiration: 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, and 62-210.300(1), F.A.C]

6. BACT Determination: 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 permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

7. 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.]

8. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. 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]

10. 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, and copies to each Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

Section III Part A. Combustion Turbines

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

Emissions Unit 006 through 009: Combined Cycle Gas Turbines No. CC-3A through CC-3D
Description: Emissions units 006, 007, 008, and 009 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. *Fuel*: The units are fired exclusively with natural gas. *Capacity*: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas 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. At a compressor inlet air temperature of 59° F, each gas turbine heat input is approximately 1600 MMBtu (LHV) per hour. *Controls*: The efficient combustion of pipeline-quality natural gas at high temperatures minimizes emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. NO_X emissions are reduced by Dry Low-NO_X (DLN) combustion technology (simple cycle mode). A selective catalytic reduction (SCR) system combined with Dry Low-NO_X (DLN) combustion technology further reduces NO_X emissions during combined cycle mode. *Continuous Monitors*: Each gas turbine is equipped with continuous emissions monitoring system (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content. *Stack Parameters*: For simple cycle operation each gas turbine has a bypass stack that is 80 feet tall and 22 feet diameter. For combined cycle operation, each heat recovery steam generator has a HRSG stack that is 120 feet tall stack and 19.0 feet diameter. When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit with an flow rate of approximately 1,004,150 (combined cycle mode) and 2,389, 462 (simple cycle mode) acfm at 202° F (combined cycle mode) and 1,116 (simple cycle mode)° F.

APPLICABLE STANDARDS AND REGULATIONS

1. <u>BACT Determinations</u>: The emissions standards specified for this unit represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), volatile organic compounds (VOCs) and sulfur dioxide (SO_2). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. <u>NSPS Subpart GG Requirements</u>: The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Gas Turbines in 40 CFR 60, Subpart GG. For completeness, the applicable Subpart GG requirements are included in Appendix GG of this permit. [Rule 62-204.800 (7), F.A.C.]

3. <u>NSPS Subpart Da Requirements</u>: Each heat recovery steam generator equipped with a 495 mmBTU/hr natural gas fired Duct Burner (LHV) shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The modification of 40CFR60, Subpart Da promulgated on September 3, 1998 also applies to this project.

EQUIPMENT

4. Gas Turbine Units 3A throughout 3D: 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 006 and 009). 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 010) 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. [Application; Design]

5. Gas Turbine Controls:

   - DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric DLN-2.6 combustion system to control NO_X emissions from each turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NO_X emissions below permitted levels. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]
   - Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, maintain and operate a SCR system to control NOx emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, electrical, piping and other auxiliary equipment. The SCR system shall be designed to reduce NO_X emissions and ammonia slip below the permitted levels. *{Permitting Note: The ammonia tank will store aqueous ammonia having a concentration of less that 20 percent ammonia. In accordance with 40 CFR 60.130, it is not subject to the Chemical Accident Prevention Provisions of 40 CFR 68}* [Rule 62-212.400(BACT), F.A.C.]

6. Heat Recovery Steam Generators: 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 (3A-3D) 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 stack 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

7. Gas Turbine Permitted Capacity: The maximum heat input rate to each gas turbine shall not exceed 1600 (normal conditions) based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of natural gas, 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.]

8. HRSG Duct Burner Permitted Capacity: The total heat input rate to the duct burners for each HRSG shall not exceed 495 MMBTU/hr based on the lower heating value (LHV) of the natural gas.
[Rule 62-210.200(PTE), F.A.C.]

9. 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 1.5 grains of sulfur per 100 standard cubic feet of natural gas.

   c. *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.

   d. *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 operate the duct burners no more than 2880 hours during any consecutive 12 months.

   e. *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) Prior to demonstrating compliance in combined cycle mode, 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 per unit during any consecutive 12 months.

   f. *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.

   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. Each gas turbine shall operate in this power augmentation mode no more than 400 hours during any consecutive 12 months.

   h. *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 in this peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation. 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.

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

EMISSIONS STANDARDS

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

Pollutant	Fuel	Method of Operation	Averaging Period	ppmvd @ 15% O2	lb/hour
CO[a]	Gas	Simple or Combined Cycle, Standard	3-hr/24-hr	7.4Test/8.0CEMS	27.5
		Simple or Combined Cycle w/PA	24-hr	12, CEMS	45.0
		Combined Cycle w/DB	3-hr/24-hr	7.4 Test/8.0 CEMS	37.5
NO_X[b]	Gas	Simple Cycle, Standard	3-hr/24-hr	9.0, Test/CEMS	58.7
		Simple Cycle w/PA	1-hr	12.0, CEMS	(82.0)
		Simple Cycle w/PK	1-hr	15.0, CEMS	(101.0)
		Combined Cycle SCR /SCR, DB, PA	3-hr/24-hr	2.5 Test/CEMS	16.3/22.1
PM/PM_{10}[c]	Gas	Simple or Combined Cycle	Fuel Specifications Visible emissions shall not exceed 10% opacity for each 6-minute average as determined by EPA Method 9 observations		
SAM/SO_2[d]	Gas	Simple and Combined Cycle	Fuel Specifications		
VOC[e]	Gas	Simple or Combined Cycle, Standard	3-hr	1.3, Test	2.8
		Combined Cycle, w/DB	3-hr	4.0, Test	9.2
Ammonia[f]	Gas	Combined Cycle, All Modes	3-hr	5.0, Test	NA

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

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-hr CO standard shall be determined separately for each mode of operation based on the hours of operation in each mode. {*Permitting Note*: 24-hr compliance average may be based on as little as 1-hr of data up to 24-hr data}.

b. Compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the NO_X 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. 9 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.}*

d. The fuel sulfur specifications in Condition No. 9 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. 27 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. 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.]

11. Duct Burners: Emissions from the duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60. [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

12. 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.]

13. 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.]

14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

15. 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.

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.]

16. Work Practice Standard and Load Restriction:
    - *Simple Cycle Work Practice BACT*: Each unit will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.
    - *Combined Cycle Work Practice BACT*: A stack damper shall be installed on each ductwork before the stack to reduce heat loss during shutdowns. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following procurement of the HRSG.
    - *Low-Load Restriction*: Except for initial steam blows, startup and shutdown, operation below 50 percent is prohibited.

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 NO_X emissions may exceed the BACT limits specified in this permit; however, NO_X 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.]

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: 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, 5B or 17	Determination of Particulate Matter Emissions from Stationary Sources {Note: For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the Department.
[Rules 62-204.800 and 62-297.100, 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, NO_X, 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 an combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in Specific Condition No. 10. 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, CEMS data may also be used to demonstrate compliance with the CO and NO_X 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. The units shall demonstrate initial compliance in accordance with the NSPS 40 CFR 60, Subpart GG and Da.
[Rule 62-297.310(7)(a)1., F.A.C.]

21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NO_X 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 are 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 NO_X from each 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.

    a. *CO Monitors.* Each 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 and combined cycle gas 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 and combined cycle gas 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. *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. [Rule 62-212.400(BACT), F.A.C.]

f. *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 Specific Condition No. 15 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.

g. *Availability*. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The report required in Appendix XS of this permit 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 will 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. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate 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 NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS, REPORTS AND NOTIFICATION

25. Monitoring of Capacity: To demonstrate compliance with the permitted capacity requirements, 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.]

26. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the 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.]

27. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis 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) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. 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.

29. Semiannual NSPS Excess Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing emissions in excess of an NSPS standard. In accordance with 40 CFR 60.7(d), the permittee shall submit the NSPS excess emissions report identified as Figure 1 and summarized in Appendix XS. 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 NO_X 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: NO_X 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]

30. Quarterly 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 emissions. The information shall be summarized for simple cycle startups, "hot" combined cycle startups, "warm" combined cycle startups, "cold" combined cycle startups, shutdowns from simple cycle, shutdowns from combined cycle, 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]

31. *Data Exclusion Reports.* A summary report of the duration of data excluded from each compliance average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. Data shall be summarized for each type of incident including steam turbine cold start, gas turbine cold start, gas turbine hot start up, shutdown and malfunction.

Section III Part B. Gas Heaters

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
010	Four gas-fired fuel heaters, 24MMBtu/hour each

APPLICABLE REQUIREMENTS

32. 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. Rule 62-204.800(7), F.A.C.; 40 CFR 60, Subpart Dc]

EQUIPMENT

33. Gas-Fired Fuel Heaters: The permittee is authorized to install four new 24 MMBtu per hour (LHV) fuel heaters. *{Permitting Note: 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

34. Permitted Capacity: Based on the lower heating value (LHV) of natural gas, each gas-fired fuel heater shall not exceed 24 MMBtu per hour. [Application; Rule 62-210.200(PTE), F.A.C.]

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

EMISSIONS STANDARDS

36. 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 62-296.320(4)(b)1, F.A.C.]

TESTING, RECORDS, AND REPORTING

37. 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.

38. 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.]

39. 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.]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

FPL Manatee Power Plant
PSD-FL-328 and 0810010-006-AC
Manatee County, Florida

BACKGROUND

The applicant, Florida Power and Light (FPL), proposes to install a new 1,150-megawatt (MW) natural gas-fueled combined cycle project (Unit 3) at its existing facility near Parrish, Manatee County. The key components include: four nominal 170-megawatt (MW) General Electric PG 7241FA (GE 7FA) combustion turbine-electrical generators; four supplementally-fired heat recovery steam generators (HRSGs) each equipped with a 495 MMBtu/hr (LHV) natural gas fired duct burners; a single 470 MW steam electrical generator and associated equipment.

Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, F.A.C. and 40 CFR 52.21(b)(23). The proposed project is subject to review for the Prevention of Significant Deterioration (PSD) for each of the mentioned pollutants and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. and 40 CFR 52.21.

Unit 3 combustion turbines will operate initially in simple cycle mode while construction continues on the steam cycle components. During the first year, simple cycle operation will be limited to 3,390 hours per year per unit. Thereafter, each gas turbine will operate in combined cycle mode continuously and in simple cycle mode up to 1000 hours per year per unit during any 12-month period. Each unit will exhaust through separate 120-foot stack with an optional 80-foot stack during limited simple cycle operation. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on February 22, 2002 (complete June 12, 2002) and included a BACT proposal prepared by the applicant's consultant, Golder Associates, Inc.

ORIGINAL BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Selective Catalytic Reduction	9 ppmvd @ 15% O_2 (simple cycle) 15 ppmvd @ 15% O_2 (simple cycle – High Power Modes)* 2.5 ppmvd @ 15% O_2 (combined cycle)
Particulate Matter	Pipeline Natural Gas Combustion Controls	9/11pounds per hour (dry filterable simple/HPMs) 17 pounds per hour (dry filterable combined)
Carbon Monoxide	As Above	9 ppmvd (Full load, Simple or Combined no DB) 14.7 ppmvd (Combined Cycle with Duct Burners) 19.2 ppmvd (Combined Cycle with DB and operating in HPM)
VOC	As Above	1.5 ppmvw (Simple/Combined Cycle no DB 7 ppmvw (Combined Cycle with DB)
Sulfur Oxides	As Above	2.0 grains sulfur/100 std cubic feet

* High Power Modes: Steam Augmentation and Peaking

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "Top-Down" approach, particularly when permits are issued by states acting on behalf of EPA. The Department considers Top-Down to be a useful tool, though not a unique or required approach to achieve a BACT under the State regulations. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by FPL is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the FPL project.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

The duct burners required for supplementary gas-firing of the HRSG are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The BACT proposed by FPL is consistent with the key historically applicable NSPS requirement of 0.20 pounds of NO_X per million Btu heat input (lb NO_X/mmBtu). It is well below the revised Subpart Da output-based limit of 1.6 lb NO_X/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for duct burners.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple and combined cycle turbines. The proposed FPL project is included to facilitate comparison.

TABLE 1

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" SIMPLE CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
FPL Manatee, FL	680	9 - NG 15 – NG –PA, PK	DLN	4x170 MW GE7FA CTs (Gas Only)
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 Issued 5/2002. 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. 500 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000/500 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
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
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.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous
SC = Simple Cycle
INT = Intermittent
PK = Peaking

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
PA = Power (Steam) Augmentation

FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

TABLE 2

RECENT CO, VOC, AND PM EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" SIMPLE CYCLE PROJECTS

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
FPL Manatee, FL	9 - NG 15 – NG –PA, PK	1.5 NG (wet)	9 lb/hr - NG 11 lb/hr – PA, PK	Clean Fuels Good Combustion
El Paso Manatee, FL	8 (7.4@15% O_2) - NG	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
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	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
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

TABLE 3

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Capacity Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
FPL Manatee, FL	1,150	2.5 – NG	SCR	4x 170 MW GE7FA CTs & DBs
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 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 (12 – simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
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

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil
PK = Peaking

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
PA = Power (Steam) Augmentation

GE = General Electric
WH = Westinghouse
CT = Combustion Turbine

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 4

RECENT CO, VOC, AND PM EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppmv (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
FPL Manatee, FL	9 (7.4 @15% O_2) - NG 15 @15% O_2 – DB 19 @15% - DB&PA/PK	1.5 – NG (wet) 7 – NG (DB)	9 – NG 17 – PA, PK 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Manatee, FL	2.5 @15% O_2) 4 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Deerfield, FL	2.5 @15% O2) 4 @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)	.00126 lb/mmBtu-NG	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Gulf Lansing Smith, FL	16 - NG (CT & DB) 23 - NG (CT&DB/ PA)	4 - NG (CT& DB) 6 NG CT&DB/PA)	10% Opacity	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 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	~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	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

All of the projects listed above control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. In every case, FERC-regulated natural gas transported through the Interstate is used. It typically has a sulfur content less than 2 grains per 100 cubic feet. In some cases, the limits are even lower or are expressed in different terms. However all ultimately rely on a fairly uniform gas distribution network and have very little flexibility in actually controlling sulfur content. Similarly, emissions of these two pollutants are controlled by using 0.05 percent sulfur distillate fuel oil during limited duel oil firing.

Some of the projects listed above include front and back half catch for PM limits. Therefore comparison is not simple.

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X 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.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 1 which is from a General Electric discussion on these principles.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as this FPL project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the FPL project. The proposed NO_X controls will reduce these emissions significantly.

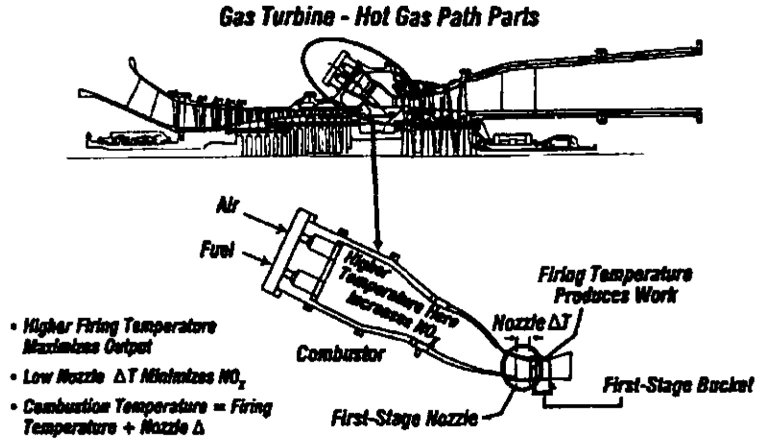

Figure 1 – Relation Between Flame Temperature and Firing Temperature

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants. The proposed turbines will not burn fuel oil.

Combustion Controls: Dry Low NO_X (DLN)

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2.

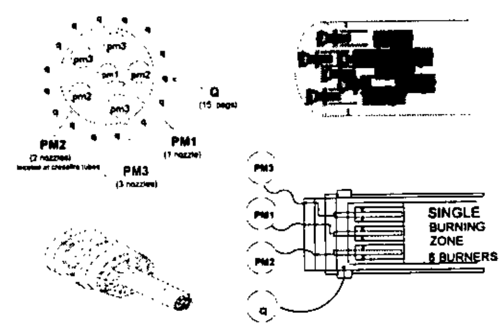

Figure 2 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X.

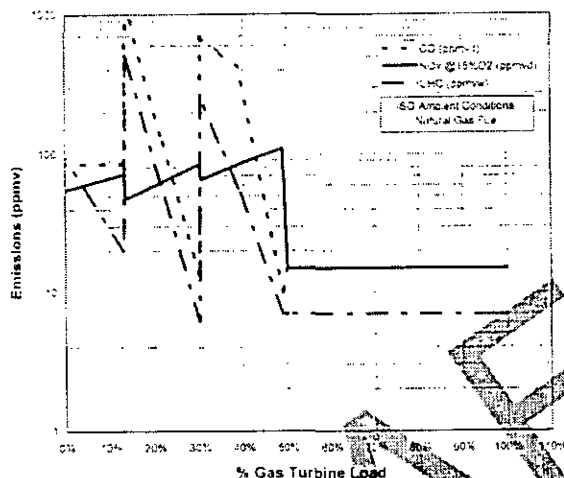

Figure 3 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd. The results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (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
Limit	10.5	15	7

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[2] The DLN-2.6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd. Selective catalytic reduction (SCR) was not used in this project. The results are also superior to the characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	
80	6.1	
90	6.6	
100	8.7	0.85
Limit	12	25

Recent conversations with other operators indicate that the "Dry Low NO_X" characteristics extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE.[3] Also during high power (steam) augmentation mode, higher emissions of NO_X and CO (more characteristic of Figure 3 above) will occur.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 4 from an EPRI report.[4] Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 4.

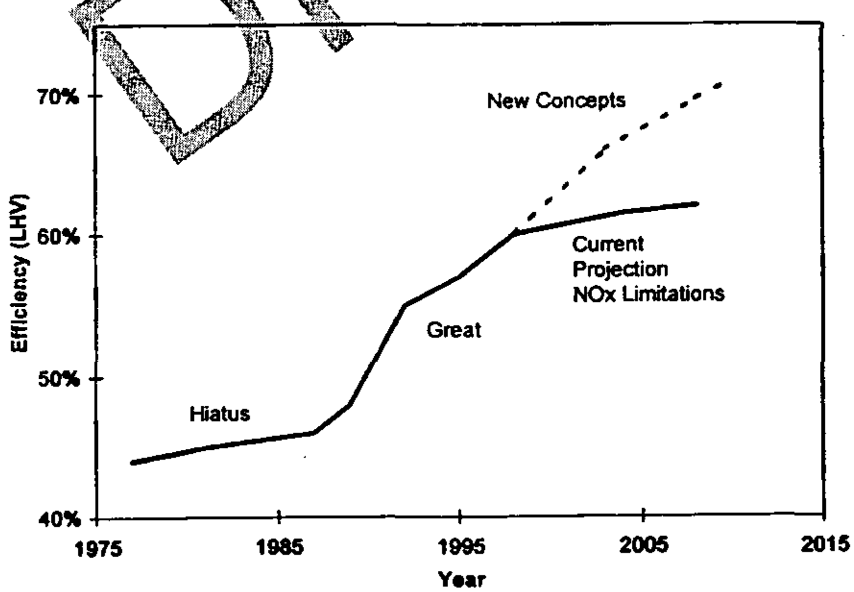

Figure 4 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by FPL. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Catalytic Combustion: XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[5] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents. Westinghouse, for example, is working to replace the central pilot in its DLN technology with a catalytic pilot in a project with Precision Combustion Inc.

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[6] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma that documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[7] The project was expected to enter commercial operation by the summer of 2001. However actual installation of XONON™ is doubtful.

In principle, XONON™ will work on a simple cycle project. However, the Department does not have information regarding the status of the technology for fuel oil firing and cycling operations.

Selective Catalytic Combustion: SCR

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued recently to Competitive Power Ventures (CPV), Calpine, Florida Power Corporation, and Tampa Electric to achieve 3.5 ppmvd. More recently, permits were issued to El Paso Merchant Energy Company for facilities in Broward, Manatee and Palm Beach counties and to CPV for its Pierce facility with a limit each of 2.5 ppmvd @15% O_2 by SCR.

Figure 5 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 6 is a photograph of FPC Hines Energy Complex. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

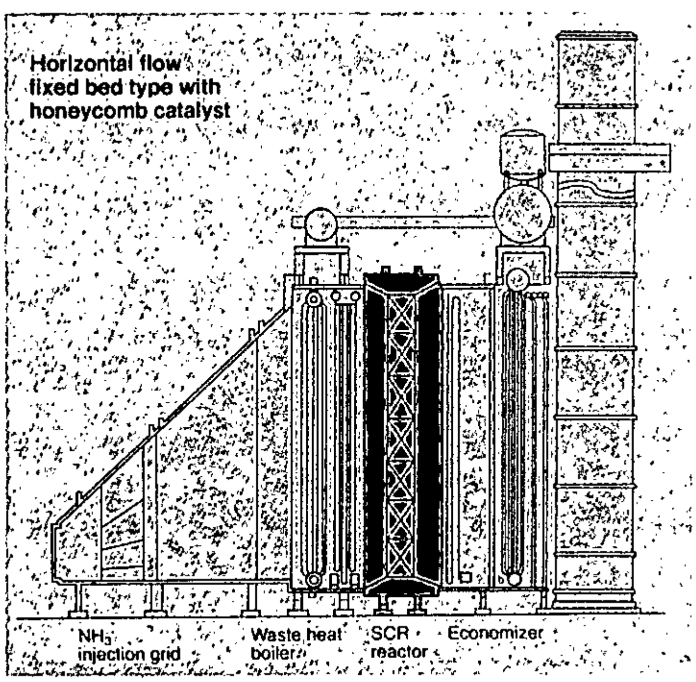

Figure 5 – SCR System within HRSG

Figure 6 – FPC Hines Power Block I

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. 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 NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center (SREC). This SREC project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

$SCONO_X$™ is a catalytic add-on technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[8]

California regulators and industry sources stated that the first 250 MW block to install $SCONO_X$™ will be at PG&E's La Paloma Plant near Bakersfield.[9] The overall project includes several more 250 MW blocks with SCR for control.[10] More recent discussions with project personnel indicate that $SCONO_X$ will not be installed at La Paloma[11].

In 1998 EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [12] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmvd. In late 2000 Goal Line announced that $SCONO_X$™ has in practice achieved emissions of 1.3 ppmvd.[13]

$SCONO_X$™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the $SCONO_X$ ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

In late 1999, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[14]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is not feasible for the limited simple cycle operation proposed in this application. It is a candidate for combined cycle operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2 from natural gas and fuel oil-fired combustion turbines.

For this project, the applicant has proposed as BACT the use of natural gas. The applicant estimated total emissions for the project at 189 TPY of SO_2 and 21 TPY of SAM. The Department expects the emissions to be lower because the typical natural gas in Florida contains less than the 1.5 grains of sulfur per 100 standard cubic feet (gr S/100scf) specification proposed by FPL. This value is well below the "default" maximum value of 20 gr S/100 scf characteristic of natural gas, but is still high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas will be the only fuel fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 224 tons per year (filterable).

CARBON MONOXIDE (CO) AND VOC CONTROL TECHNOLOGIES

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO and VOC emissions is the use of an oxidation catalyst.

Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. There is a great deal of uncertainty regarding actual CO and VOC emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are typically reported (at least at full load operation) without use of oxidation catalyst.

Based on testing discussed in the NO_X technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Similarly, VOC emissions less than 1 ppm have consistently been measured at new units throughout the state.

CO and VOC emissions *should* be low because of the very high combustion temperatures characteristic of "F-Class" turbines. It appears that contract writing has not yet "caught up" with the field experience to consistently guarantee low CO and VOC emissions for F-Class units throughout the range of normal operation.

The presence of a duct burner and possibility of other high power modes (steam augmentation and peaking) complicate the evaluation somewhat. FP&L has requested greater CO emission limits for those three cases and greater VOC emissions when using the duct burners.

Following is a table with the results of CO and VOC testing recently completed at Gulf Power Plant Smith.[15] The units tested were GE7FA combustion turbines of the same type that FP&L will install at the Manatee Power Plant. Tests were conducted on each combustion turbine during simultaneous power (steam) augmentation mode and also with duct burners in operation.

CO and VOC Emissions (ppmvd@15% O_2) from Gulf Power, Plant Smith Units 4 & 5

Unit/Modes	CO	CO Limit	VOC	VOC Limit
Unit 4/Duct Burner	1.21	16	0.15	4
Unit 5/Duct Burner	1.26	16	0.31	4
Unit 4/Power Augmentation	5.18	23	0.61	6
Unit 5/Power Augmentation	8.61	23	0.38	6

As seen from the table above, emissions of CO are greater during power augmentation, but quite low when using the duct burner. VOC emissions are low under both cases. No tests were conducted during "peaking." However, according to information from General Electric, CO emissions during "peaking" will actually be less than such emissions during normal operation. This is because of higher flame temperature in the combustors during peaking compared with normal operation.[16]

The main control strategy is the installation of oxidation catalyst. Such equipment is typically installed (when cost-effective) to achieve emissions in the range of 2 to 4 ppm of CO. Emissions of CO and VOC from combustion turbines such the ones installed are very low except during power augmentation, so usually oxidation catalyst is not warranted.

Nevertheless, El Paso will install oxidation catalyst at planned combined cycle projects using GE7FAs in Broward, Palm Beach, and Manatee Counties. The purpose of the catalyst is to limit CO emissions during continuous power augmentation as opposed to the less frequent power augmentation planned by FP&L for the Manatee Unit 3 project.

The Department recently issued a permit requiring oxidation catalyst on a Mitsubishi 501F combustion turbine at the planned Enron/Fort Pierce Repowering project. The reason was to avoid high CO emissions exhibited by this model (even without duct burners or power augmentation) at low and medium loads. The CO emission limit with oxidation catalyst was 3.5 ppmvd at full load. This would not have been a concern if the units were GE7FAs because those have good CO emissions characteristics between 50 and 100 percent of full load.

The CO limit proposed by FPL under normal operation is 9 ppmvd (7.4 ppmvd @15% O_2) at full load simple or combined cycle. FPL proposed higher CO limits of 14.7 ppmvd @15% O_2 during duct burning and 19.2 ppmvd @15% O_2 during duct burning combined with power augmentation or peaking modes for the combined cycle unit. The proposed VOC limits are 1.5 ppmvw without the duct burner and 7 ppmvw when using the duct burner.

Total respective emissions of CO and VOC for the project, as originally proposed by FP&L, are 749 and 99 tons per year. Actual emissions will probably be much lower based on the Gulf Power tests.

BACKGROUND ON PROPOSED GAS TURBINE

FPL plans to install four nominal 170-MW General Electric 7FA gas turbines, which will operate in simple mode (3,390 hours during the first year while the steam cycle components are under construction. Thereafter the combustion turbines will operate continuously in combined cycle and up to 1000 hours per year per unit in simple cycle. Per the discussion above, such units are capable of achieving and have achieved (with DLN and SCR technology) all of the emission limits proposed by FPL as BACT.

The GE Speedtronic™ Mark VI Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include fuel control in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions.

The Mark VI also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[17]

STARTUP AND SHUTDOWN EMISSIONS

The Department defines "Startup" as follows[18]:

"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.

The Department permits excess emissions during startup and shut down as follows:[19]

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.

The Department defines "Excess Emissions" as follows:[20]

"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, sootblowing, load changing or malfunction.

The U.S. EPA Region IV office recently recommended that the Department consider "establishment of startup and shutdown BACT for CO and NO_X such as mass emission limits (e.g., pounds of emissions in any 24-hour period) that include startup and shutdown emissions, or future emission limits derived from monitoring results during the first few months of commercial operation."[21]

The Department reviewed a number of emission estimates and permit conditions addressing startup and shutdowns for projects in California, Georgia, Washington, and Mississippi and has determined that much of the information is based on estimates that are very difficult to verify.

A review of published General Electric information indicates that features are incorporated into the design of the DLN-2.6 technology specifically aimed at minimizing emissions. One of the key elements was to incorporate lean pre-mixed burning while operating the unit in low load and startup.[22]

This is in contrast with the previous DLN-2.0 technology that relied on diffusion mode combustion at four of the burners in each combustor during startup and low load operation.

During startup of a GE 7FA simple cycle unit, NO_X concentrations in the exhaust are greater than during full-load operation. The concentrations are estimated at 20 to 80 ppmvd @15% O_2 during the first 10 minutes or so after the unit is actually firing fuel. This occurs while only one to four of the six nozzles shown in Figure 2 are in operation on each combustor.

Within the following 5 minutes, the unit switches to Mode 5 (or 5 Q), during which NO_X concentrations are typically less than 10 ppmvd even though the unit is not yet at full load.[23] The Low-NO_X modes occur when at least the five outer nozzles are in operation.

Given the short duration and the relatively low exhaust rate (and load) during the high pollutant concentration phases of simple cycle startup, the Department believes that the NO_X emissions during the first hour of startup and operation will be approximately equal to emissions during an hour of full load steady-state operation. Arguments covering shutdown are similar and the time is more compressed so that the Department believes the conclusion is the same for startup as for shutdown.

NO_X concentrations in the exhaust during startup and shutdown will be less than the New Source Performance Standard limit of approximately 110 ppmvd @15% O_2 applicable to F-Class turbines. A simple cycle unit will typically have one startup and shutdown every day that it is used.

The startup scenarios for a GE 7FA combined cycle unit are as follows:

Hot Start: One hour following a shutdown less than or equal to 8 hours.
Warm Start: Two hours following a shutdown between 8 and 48 hours.
Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

During a combined cycle cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated up. During a portion of the 4-hour startup, emissions will be roughly 60 to 80 ppmvd NO_X @15% O_2. Once the HRSG is heated sufficiently, the ammonia system is turned on to abate emissions.

While NO_X emissions during the initial phase of startup (low load and no ammonia injection) are greater than during full load steady state operation, such startups are infrequent. Also, it is noted that such a cold startup would be preceded by a shutdown of at least 48 hours. Therefore the startup emissions would not cause annual emissions greater than the potential-to-emit under continuous operation. Similar analyses can be performed for warm startups and hot startups.

The combined cycle startup scenario described above can (at least in theory) be modified by use of the bypass stack already proposed simple cycle operation and damper or special valve.[24] Under this scenario, the steam cycle can be slowly brought up to load while the gas turbine reaches low emission modes as fast as it would under simple cycle mode. The exhaust gas can be modulated in such a fashion that the HRSG and steam turbine are ramped up slowly in accordance with their respective specifications. At the same time, the gas turbine will quickly accelerate to the DLN modes (5Q or 6Q) thus minimizing emissions. In this manner the startup NO_X and CO concentrations can be reduced to the values observed during simple cycle startup. Thereafter the unit will exhibit the same characteristics (for about three hours) as a simple cycle unit in steady-state operation until the ammonia system is actuated.

Implementation of bypass modulation would also require features to minimize stratification and uneven heating of boiler tube bundles in the HRSG. The initial response from GE is that such a configuration (modulating with a damper) at a project in Hungary resulted in equipment damage and leakage of exhaust gas to the atmosphere resulting in a significant loss in performance.[25]

According to FP&L, even with special valves, there will be gas leakage and losses in efficiency. For that reason they actually blank off the bypass stack entirely when the unit operates in combined cycle at their Fort Myers Plant. To operate the unit using the bypass stack, they would actually need to shut it down, allow cooling, remove the plate from the simple cycle stack, and blank off ducting to the HRSG.

The difficulty on switching over from combined cycle to simple cycle is also good reason to expect only minimal simple cycle operation. This might actually occur if and when the steam turbine has to be shut down for an extended period of time.

The Department is gathering information from recently commissioned 7FA units to more accurately estimate startup emissions for NO_X and address carbon monoxide too.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the FPL project assuming full load. Values for NO_X, VOC and CO are corrected to 15% O_2 on a dry volume basis. These emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are specified in the permit.

POLLUTANT	CONTROL TECHNOLOGY	DEPARTMENT'S PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X	9 ppmvd @ 15% O_2 (simple cycle normal) 12 ppmvd @ 15% O_2 (simple cycle - PA) 15 ppmvd @ 15% O_2 (simple cycle – PK)
	SCR	2.5 ppmvd @ 15% O_2 (combined cycle)
Particulate Matter	Natural Gas Combustion Controls	10 percent opacity, Fuel Specifications 5 ppm ammonia slip from combined cycle unit
Visible Emissions	As Above	10 Percent opacity
Carbon Monoxide	As Above	7.4/8.0 ppmvd @15% O_2 (full load/continuous) 12 ppmvd @15% O_2 (400 hours - PA)
Sulfur Oxides	As Above	1.5 grain sulfur/100 std cubic feet
Volatile Organic Compounds	As Above	1.3 ppmvd @15% O_2 4 ppmvd @15% O_2 (Duct Burner)
Gas Heaters	Low Sulfur Fuels	1.5 grain sulfur/100 std cubic feet

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

RATIONALE FOR DEPARTMENT'S DETERMINATION

- Certain control options are feasible on combined cycle modes but not on simple cycle modes. This rules out Low Temperature (conventional) SCR, and $SCONO_X$ on simple cycle modes. XONON is claimed to be available for F Class gas-fired projects.
- The "top technology" and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are high temperature (Hot) SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- The levelized costs of NO_X removal by Hot SCR for the FPL project were estimated by FPL at \$20,156 and \$51,647 per ton assuming 3390 and 1000 hours of operation respectively. The estimates are based on reducing NO_X emissions from 9 to 3.5 ppmvd @15% O_2.
- The Department does not necessarily accept the Hot SCR cost calculations presented by FPL and considers them on the high end. But even at half the cost estimated by FPL, the Department would agree that Hot SCR is not cost-effective for this project.
- XONON is rejected because it has not yet been demonstrated in large combustion turbines and is likely to be even less cost-effective than Hot SCR.
- The Department accepts FPL's BACT proposal of 9 ppmvd NO_X @15% O_2 for the normal simple cycle mode <u>and</u> exclusive use of natural gas. The Department notes that data from the City of Tallahassee and TECO demonstrate that the GE 7FA units achieve 6 to 8 ppmvd @15% O_2.
- The Department accepts FPL's BACT proposals of 12/15 ppmvd NO_X @15% O_2 during the limited periods of power augmentation/peaking (400/60 hours).
- The proposed BACT limit of 9 ppmvd for the normal simple cycle mode is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The Department will limit the first year of operation to an average of 3,390 hours per year per simple cycle unit. After the first year, the Department will further limit the operation of each and every individual unit to 1000 hours per year per unit.
- Although startup and shutdown emissions are generally exempt, emissions during startup and shutdown are less than the NSPS limit of 110 ppmvd @15% O_2 (that applies during steady-state operation).
- The Department does not yet have sufficient information from field experience to set start-up and shutdown emissions limits. However, the modes that give rise to high NO_X concentration have been identified. The Department will therefore set a work practices standard as BACT.

- The Work Practice BACT for simple cycle startup is that the unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. Shutdowns shall include no more than 10 minutes of operation in Modes 1, 2, 3, and 4, combined.
- The Lowest Achievable Emission Rate (LAER) for a combined cycle unit is approximately 2 ppmvd NO_X at 15 percent oxygen (@15% O_2) while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line, has requested recognition of a 1.3 ppmvd NO_X value as *achieved in practice*.
- There are several projects for large turbines in Massachusetts, Connecticut, New York, and California, requiring SCR with a NO_X emission limit of 2 ppmvd @15% O_2.
- The "Top" technology in a top/down analysis for a combined cycle unit will achieve approximately 2 ppmvd @15% O_2 by either $SCONO_X$ or SCR.
- FPL estimated the cost effectiveness of $SCONO_X$ at $22,341 per ton of NO_X removed . The Department does not necessarily accept the precise $SCONO_X$ cost calculations presented by FPL. However, even at half the cost estimated by FPL, the Department agrees that $SCONO_X$ would not be cost-effective for this project.
- FPL estimated the cost-effectiveness of conventional (cold temperature) SCR at $4,900 per ton of NO_X while reducing emissions from 9 to 3.5 ppmvd @15% O_2. The estimate to achieve 2.5 ppmvd @15% O_2 is $5,200 per ton. The Department believes FPL's estimates are somewhat the high side, but agrees with FPL that this technology is cost-effective.
- The National Park Service advised in its review of the application that BACT determinations of 2.0 ppmvd NO_X @15% O_2 have recently been issued for combined cycle projects in Maine and Washington.[26] They recommended similar limit for the FPL project.
- FPL estimated the "incremental cost" to further reduce NO_X emissions from 2.5 to 2.0 ppmvd @15% O_2 of $12,064 per ton. However, using FPL's estimates, the average cost of lowering NO_X emissions from 9 to 2 ppmvd @15% O_2 would be about $5,600 per ton. Such a value appears cost-effective.
- In their review of the El Paso Manatee project, EPA advised that the proposed 2.5 ppmvd limit is equal to the lowest value established in Region IV, that the 24-hour averaging time is acceptable in light of the low limit, and that the ammonia limit is consistent with projects outside the Region (notwithstanding lack of rule authority or a policy within EPA).
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.0-3.5 ppmvd).[27]
- A lower limit would mean additional NO_X reductions of approximately 65 tons for the project. The Department, however, proposes a BACT limit of 2.5 ppmvd NO_X @15% O_2 (5 ppmvd ammonia slip) while firing natural gas in combined cycle operation. This value takes into consideration the measurement uncertainties at very low emission rates.

- The effects of aqueous ammonia use and ammonia slip are not unacceptable. In fact, ammonia is used throughout the nearby fertilizer complexes in Hillsborough, Polk, and Manatee County.
- The Department's overall BACT determination for combined cycle operation is less than 0.07 lb of NO_X per megawatt-hour (lb/MWH) by Dry Low NO_X.
- The company will install a damper-in the ductwork between the HRSG and stack to retain as much heat as possible during periods of shutdown. This will tend to reduce the number of long cold startups in comparison with the shorter hot startups.
- Duct burners used for supplementary firing will easily comply with the NSPS (Subpart Da). They will cause higher NO_X mass emission rates than permitted for the combustion turbine alone, but emissions must meet the same concentration standard of 2.5 ppmvd @15% O_2 requirement.
- The applicant estimates VOC emissions of 1.3 ppmvd @15% O_2 under all modes except duct firing in combined cycle mode. For duct firing FPL requested 5.0 ppmv<u>d</u> @15% O_2 (actually 7 ppmv<u>w</u>). The Department accepts FPL's proposal, but will adjust the limit during duct firing to equal the limit set for the Gulf Power project of 4 ppmvd @15% O_2. It is noted that Gulf Power easily complied with the lower value.
- FPL did not estimate CO levelized control costs for the first year simple cycle operation. During the first year, power augmentation will not be practiced. Peaking actually results in lower CO emissions. The combination of limited operation during the first year (3,390 hr/yr), a low limit of 7.4 ppmvd @15% O_2, no high CO emission modes, and expected emissions of approximately 1-2 ppmvd @15% O_2 insure that oxidation catalyst is not cost effective or warranted.
- FPL estimated levelized costs for oxidation catalyst control at $4,409 to reduce CO emissions from all operational modes after startup of combined cycle operation. This includes reducing CO emissions from 9, 14.7 and 19.3 to 2 ppmvd @15% O_2 for normal, duct burning, and peaking/power augmentation.
- The Department does not necessarily agree with FPL's cost estimate for oxidation catalyst, but agrees that it is not cost-effective with the specific BACT limits proposed by the Department.
- Because peaking does not increase CO and because the Gulf Power tests indicated very low emissions during duct burning, the Department will set a limit for those modes equal to the continuous limit for the normal mode of 8 ppmvd @15% O_2.
- The Department determines BACT for CO achievable by good combustion as 7.4 ppmvd @15% O_2 at full load and 8 ppmvd @15% O_2 (24 hr average time) over the full operational range for simple cycle and combined cycle operation.
- Because CO emissions actually increase during power augmentation, a higher limit will be set for that mode. While the tests at Gulf Power indicated emissions as high as 9 ppmvd during power augmentation, it is prudent to provide a margin of safety to 12 ppmvd @15% O_2 as requested by FPL.
- Due to limited power augmentation (400 hours per year per unit), low CO emission limit for all other modes, and likely very low emissions (as demonstrated by Gulf Power tests), the Department has reasonable assurance that oxidation catalyst is not cost-effective for this project.

- BACT for sulfur oxides for this project (including the ancillary equipment emission units) is the exclusive use of natural gas with a specification of 1.5 grains per 100 standard cubic feet. Natural gas in Florida contains less than this value.
- The Department agrees that inlet air filtration, good combustion, and use of inherently clean fuels constitute BACT for PM/PM_{10} for this project (including ancillary equipment emission units).
- The fuel specification for natural gas and the visible emissions limitation of 10 percent opacity will also be specified as work practice standard for PM/PM_{10}.
- The emission rates for PM_{10} for simple cycle modes will be approximately 9 for normal simple cycle mode and 11 pounds per hour for peaking/powering augmentation modes. The value during combined cycle operation will be 17 pounds per hour. These values are based on filterable fraction only per the Department's definition of PM/PM_{10}. Expected particulate emissions based on filterable plus condensable particulate matter are closer to 20 and 40 pounds per hour for simple and combined cycle operation respectively.

BACT LIMIT COMPLIANCE REQUIREMENTS

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions (initial, annual)	Method 9
PM/PM_{10} (initial)	Method 5 (Front-half catch)
VOC	Method 25A corrected by methane from Method 18
CTM-027(initial, quarterly, annual)	Procedure for Collection and Analysis of Ammonia in Stationary Sources
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
CO (initial, annual, CEMS)	Method 10; CO-CEMS (continuous 24 -hr block average)
NO_X (continuous 24-hr average) NO_X (PK or PA, 1-hr average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (initial and annual)	Annual Method 20 (can use RATA if at capacity); Method 7E

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

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Teresa Heron, Permit Engineer
A. A. Linero, P.E. Administrator ______________________
New Source Review Section
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Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

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Date

Approved By:

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Howard L. Rhodes, Director
Division of Air Resources Management

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Date

DRAFT

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27 Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

G.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.

G.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 or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any 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.

G.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.

G.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.

G.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.

G.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.

G.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.

G.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 extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.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.

G.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.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.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).

G.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.

G.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

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

<u>Department requirement</u>: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NO_X CEMS. The "Y" value for this unit is approximately 10 for natural gas. The equivalent emission standard is 108 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: **The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.**

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: **NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.**

[Note: 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 CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\ (Pr/Po)^{0.5}\ e^{19(Ho-0.00633)}\ (288°K/Ta)^{1.53}$$

where:

NOx	=	emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H_2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NO_X monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the BACT NO_X limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be 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 paragraph (c)(3) above.

[Note: 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.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

<u>Department requirement</u>: The permit specifies sulfur testing methods.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

{Permitting Note: 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 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.]

4. 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

5. 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.]

6. 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.]

7. 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.]

8. 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.]

9. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

10. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

11. 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.]

RECORDS AND REPORTS

12. 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.]

13. 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.]

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

CONTINUOUS MONITOR SYSTEMS SEMI-ANNUAL REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From ______________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ______________________________

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ______________________________

Total source operating time in reporting period [a]: ______________________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

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

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months.

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

____
Name

____
Title

____ ______________________
Signature *Date*

Gibson, Victoria

From: Kissel, Gerald
Sent: Wednesday, August 07, 2002 9:06 AM
To: Gibson, Victoria
Subject: RE: Address for ManaSota 88, Inc.

Address is P.O. Box 1728
Nokomis, FL 34274

-----Original Message-----
From: Gibson, Victoria
Sent: Tuesday, August 06, 2002 11:44 AM
To: Kissel, Gerald
Subject: Address for ManaSota 88, Inc.

Good morning.

I sent ManaSota 88, Inc. a copy of the Draft Permit for FPL Manatee Power Plant / 1150 Megawatt Combined Cycle Power Project. The Post Office returned it to me saying that the forwarding order had expired for this address:

PO Box 14119
Bradenton, FL 34280

Do you have a different address for them? Do you know if this group still formally exists?

I found an old e-mail site off the web that listed Gloria Range as an officer of this group. I have called information in the Manatee and Sarasota areas. The operator found a Ms. Gloria Range at this number of 941-722-7413. However, there is no Ms. Range at that number now. The person who answered the phone did not recognize the name ManaSota 88 and therefore could provide no further information.

Thank you very much for your response.

Victoria Gibson
Administrative Secretary
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Regulation
850-921-9504 FAX: 850-922-6979
Email: victoria.gibson@dep.state.fl.us

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:

Amy E. Stein, Chair
Manatee County Board of
County Commissioners
PO Box 1000
Bradenton, FL 34206-1000

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Corey L. Farnham

B. Date of Delivery

C. Signature

Terry L. Farnham

☒ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes

If YES, enter delivery address below: ☒ No

JUL 26 2002 BRADENTON

3. Service Type

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

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

7001 0320 0001 3692 8260

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)

OFFICIAL USE

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

Postmark Here

7001 0320 0001 3692 8260

Sent To Amy E. Stein
Street, Apt. No.; or PO Box No. PO Box 1000
City, State, ZIP+4 Bradenton, FL 34206-1000

PS Form 3800, January 2001 See Reverse for Instructions

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:

Clarence Troxell
3321 Lakeside Circle
Parrish, FL 34219

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Clarence G. Troxell

B. Date of Delivery 7-27-02

C. Signature

X Clarence G. Troxell

☒ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes

If YES, enter delivery address below: ☒ No

3. Service Type

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

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

7001 0320 0001 3692 8277

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)

OFFICIAL USE

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

Postmark Here

7001 0320 0001 3692 8277

Sent To Clarence Troxell
Street, Apt. No.; or PO Box No. 3321 Lakeside Circle
City, State, ZIP+4 Parrish, FL 34219

PS Form 3800, January 2001 See Reverse for Instructions

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. Paul Plotkin
Plant General Manager
Florida Power and Light
19050 State Road 62
Parrish, FL 34219

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) GALE KINNE
B. Date of Delivery 07-26-07
C. Signature X Gale Kinne ☐ Agent ☐ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

7001 0320 0001 3692 8307

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)

OFFICIAL USE

7001 0320 0001 3692 8307

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

Postmark Here

Sent To Paul Plotkin
Street, Apt. No.; or PO Box No. 19050 State Road 62
City, State, ZIP+4 Parrish, FL 34219

PS Form 3800, January 2001 See Reverse for Instructions

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:

ManaSota 88, Inc.
P. O. Box 1728
Nokomis, FL 34274

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) Compton
B. Date of Delivery C
C. Signature X Glen Compton ☐ Agent ☐ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

NOKOMIS FL AUG 16

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

7001 0320 0001 3692 8161

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)

OFFICIAL USE

7001 0320 0001 3692 8161

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

Postmark Here

Sent To ManaSota 88, Inc.
Street, Apt. No.; or PO Box No. PO Box 1728
City, State, ZIP+4 Nokomis, FL 34274

PS Form 3800, January 2001 See Reverse for Instructions