INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 28-Apr-2000 01:09pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Ken Kosky (kkosky@golder.com)

Subject: Gas Turbine Formaldehyde Emissions

Ken,

This is similar to Al's request with regard to MACT for gas turbines. EPA Region 4 has told me they will comment on the Palmetto Power project. One of their concerns is the formaldehyde emissions factor you referenced in the application (Golder, 1998). If you could you provide me the background information for this reference, it would help me in preparing a response.

Thanks. Have a good weekend.

Jeff

Revised version emailed to Rich P.per on 5-11-00 to correct District Office from CD to SED.
JFK

April 28, 2000

Certified Mail - Return Receipt Requested

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

Re: DEP File No. 0850001-008-AC (PSD-FL-286)
FPL Martin Plant
Addition of Two 170 MW Simple Cycle Peaking Combustion Turbines

Dear Mr. Lindsay:

Enclosed is one copy of the draft air construction permit to install two new simple cycle combustion turbines at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Department's Technical Evaluation and Preliminary Determination, Intent to Issue Air Construction Permit, and the Public Notice of Intent to Issue Air Construction Permit are also included.

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

Please submit any 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 other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

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

CHF/jfk

Enclosures

In the Matter of an
Application for Permit by:

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

ARMS Project No. 0850001-008-AC
PSD Permit No. PSD-FL-286
FPL Martin Power Plant
Emission Units 011 – 014
Martin County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of draft permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Florida Power and Light, applied on February 19, 2000 to the Department for an air construction permit to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The Draft Permit authorizes the installation of two simple cycle, dual-fuel, General Electric Model PG7241(FA) combustion turbines-electrical generator sets, each having a generating capacity of 170 MW.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances 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, and 62-297, F.A.C.

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 Air Construction 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 Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written 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.

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

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

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

Mediation is not available in this proceeding.

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

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

Mr. John M. Lindsay, FPL*
Mr. Richard G. Piper, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Clerk Stamp

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

______________________ (Clerk) ____________ (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

FPL Martin Power Plant
Martin County

Draft Permit No. 0850001-008-AC (PSD-FL-286)
Two New Simple Cycle Combustion Turbines
New Emissions Units 011 - 014

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power and Light (FPL) Company to increase peaking power at the existing FPL Martin Power Plant. This plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The applicant proposes to install of two simple cycle gas turbines, two natural gas fired fuel heaters, and a distillate oil storage tank. Each gas turbine is a General Electric Model PG7241(FA) combustion turbine-electrical generator set with a nominal generating capacity of 170 MW. A determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. Although this project is located at a plant subject to the Power Plant Siting Act, it is not subject to review under Section 403.506, F.S., because it provides for no expansion in steam generating capacity. The applicant's authorized representative is John M. Lindsay, Plant General Manager, for the FPL Martin Power Plant. The applicant's mailing address is P.O. Box 176, Indiantown, FL 34956.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. NOx emissions will be controlled with dry low-NOx combustion technology when gas firing and with water injection when oil firing. Emissions of particulate matter, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of clean fuels. Under normal gas firing conditions, General Electric guarantees CO and NOx emissions of 9 ppmvd corrected to 15% oxygen for the Model PG7241(FA) gas turbine. When firing very low sulfur distillate oil as a backup fuel, General Electric guarantees CO and NOx emissions of 20 and 42 ppmvd corrected to 15% oxygen, respectively. Each unit will be restricted to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for *power augmentation* during peak demand periods, typically summer. The power augmentation mode is restricted to 500 of the allowable hours when firing only natural gas with CO and NOx emissions limited to 15 and 12 ppmvd corrected to 15% oxygen, respectively.

The following table summarizes the project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	**Project Potential Annual Emissions (Tons Per Year)**	**Significant Emissions Rate (Tons Per Year)**	**Significant? (Table 212.400-2)**	**BACT Required?**
CO	140	100	Yes	Yes
NOx	374	40	Yes	Yes
PM/PM_{10}	35	15	Yes	Yes

notice to be published in the newspaper

SAM	5	7	No	No
SO_2	67	40	Yes	Yes
VOC	14	40	No	No

An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. 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 this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written 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.

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

notice to be published in the newspaper

address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

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

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue (P.O. Box 15425)
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6755

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 Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

{Note: This document was revised on 05/11/00 to correct the District Office location from the Central District to the Southeast District.}

notice to be published in the newspaper

FLORIDA

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

April 28, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. Douglas Neeley, Chief
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: Request for Approval of Custom Fuel Monitoring Schedule
FPL Martin Power Plant
PSD Permit No. PSD-FL-286

Dear Mr. Neeley:

Enclosed is a copy of the Department's draft permit authorizing the installation of two simple cycle, General Electric Model PG7241(FA) combustion turbines with electrical generator sets fired primarily with natural gas. The draft permit also allows up to 500 hours per year of very low sulfur distillate oil as a backup fuel. Each gas turbine is capable of producing a nominal 170 MW of electricity. The existing electric power generating plant is located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. Completion of this project will result in a nominal power production of 2940 MW for the entire plant. The Department's Intent to Issue package was also mailed to Mr. Gregg Worley of Region 4 for comments regarding the BACT determinations.

Please send your written comments on, or approval of, the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% oxygen or a fuel sulfur limit of 0.8% sulfur by weight. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas, which has a maximum SO_2 emission rate of 0.0006 lb/mmBTU (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 1 grain per 100 standard cubic feet (0.003 % sulfur by weight). The requirements have been incorporated into the enclosed draft permit and read as follows:

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

(a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by 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 equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan) or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

Y. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

(a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

(c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2), provided:

(1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

(2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

(3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d). [40 CFR 60, Subpart GG; Applicant Request]

Also, please comment on these conditions with respect to the use of the acid rain NOx CEMS for demonstrating compliance as well as reporting excess emissions. Typically NOx emissions will be less than 10 ppmvd corrected to 15% oxygen for gas firing which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedules and these NOx monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Jeff Koerner at 850/414-7268.

Sincerely,

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/jfk

Enclosures

Z 341 355 282

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Doug Neeley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-5-00	
0850001-005-AC P50-F1-286	

PS Form 3800, April 1995

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. Doug Neeley, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 5-4-00

C. Signature
X [signature] ☐ 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

2. Article Number *(Copy from service label)* Z 341 355 282

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief – Bureau of Air Regulation

THROUGH Al Linero, Administrator - New Source Review Section *Ial*

FROM: Jeff Koerner, Project Engineer - New Source Review Section

DATE: April 27, 2000

SUBJECT: FPL Martin Plant
Two Nominal 170 MW Simple Cycle Peaking Combustion Turbines (PSD-FL-286)

Attached is the public notice package to install two new 170 MW simple cycle combustion turbines at FPL's existing power plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. Each unit is a General Electric Model PG7241(FA) gas turbine-electrical generator set capable of producing a nominal 170 MW of electricity. Completion of this project will result in a nominal production capacity of 2940 MW for the existing power plant.

The peaking units will be fired primarily by natural gas with low sulfur distillate oil as a backup fuel. Each unit will be restricted to 3390 hours of operation during any consecutive 12 months, of which no more than 500 hours may be oil firing. The draft permit authorizes steam injection for *power augmentation* during high demand periods, typically summer. Power augmentation (PA) is limited to 500 hours per year and only when firing natural gas. CO and NOx emissions are slightly higher during the power augmentation mode. The draft permit includes the following BACT standards.

<u>CO Emissions</u>: Achieved by the efficient combustion of clean fuels

- Gas Firing, Normal: 9 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
- Gas Firing W/PA: 15 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
- Distillate Oil Firing: 20 ppmvd @ to 15% O_2 based on a 3-hour average, annual test

<u>NOx Emissions</u>: Achieved by dry low-NOx combustion for gas firing and water injection for oil firing

- Gas Firing, Normal: 9 ppmvd @ to 15% O_2 based on a 3-hour average, annual test
  10 ppmvd @ to 15% O_2 based on a 3-hour average, CEMS data
- Gas Firing W/PA: 12 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data
- Distillate Oil Firing: 42 ppmvd @ to 15% O_2 based on a 3-hour average, annual test and CEMS data

<u>PM/PM_{10} and SO_2 Emissions</u>: Achieved by the efficient combustion of clean fuels

- Firing natural gas as the primary fuel and distillate oil as a backup fuel containing $\leq$ 0.05% sulfur by weight
- 5% opacity or less when firing natural gas and 10% opacity or less when firing distillate oil, annual test

<u>VOC Emissions</u>: Very low emissions do not trigger a BACT determination for this project

<u>Excess Emissions</u>: Operation below 50% of base load shall not exceed 120 minutes per day. During periods of startup and shutdown, visible emissions are limited to 20% opacity for up to ten, 6-minute observation periods per day. NOx emissions must be recorded during startup, shutdown, and malfunction, but the permittee may exclude two CEMS hourly averages per day due to excess emissions resulting from these conditions.

Day #74 is June 26, 2000. I recommend your approval of the attached Intent to Issue package for this project.

JFK

Attachments

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911

PROJECT DESCRIPTION

The draft permit authorizes installation of two new 170 MW simple cycle combustion turbines at FPL's existing power plant located in Martin County. Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set capable of producing a nominal 170 MW of electricity. Each peaking unit will be fired primarily with natural gas and restricted to 3390 hours per consecutive 12 months. Of this total, no more than 500 hours may occur when firing low sulfur distillate oil as a backup fuel. The draft permit authorizes steam injection for *power augmentation* (PA) to accommodate summer peaking demands. Operation in the PA mode is limited to 500 hours per year and only when firing natural gas. CO and NOx emissions are slightly higher during the PA mode. Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I Area (Everglades National Park) and Class II areas. The draft permit includes the following BACT standards.

CO emissions will be achieved by the efficient combustion design and shall not exceed: 9 ppmvd @ 15% O_2 for gas firing (test); 15 ppmvd @ 15% O_2 for gas firing w/PA (test); and 20 ppmvd @ 15% O_2 for oil firing (test).

NOx emissions will be achieved by dry low-NOx combustion for gas firing, water injection for oil firing and shall not exceed: 9 ppmvd @ 15% O_2 for gas firing (test); 10 ppmvd @ 15% O_2 for gas firing (CEMS); 12 ppmvd @ 15% O_2 for gas firing w/PA (test and CEMS); and 20 ppmvd @ 15% O_2 for oil firing (test and CEMS).

PM/PM_{10} and SO_2 emissions will be achieved by efficient combustion, the firing of natural gas as the primary fuel and the firing of distillate oil containing less than 0.05% sulfur by weight as a backup fuel. Opacity is limited to 5% or less when firing natural gas and 10% or less when firing distillate oil.

VOC emissions will be minimized by the use of clean fuels and efficient combustion. The inherently low VOC emissions did not trigger a BACT determination for this project.

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

Jeffery F. Koerner (signature) — 4-27-00

Jeffery F. Koerner, P.E.
Registration Number: 49441

Date

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

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 14-Apr-2000 05:22pm
From: Kosky, Ken
KKosky@GOLDER.com
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)
CC: Alvaro Linero TAL (Alvaro.Linero@dep.state.fl.us)
CC: Rich Piper (Rich_Piper@fpl.com)

Subject: Re: FPL Martin Plant - Peaking Units

Jeff: GE did not supply power augmentation for 59 degrees F, since GE stated that steam power augmentation is only permitted above 59 degrees F. Refer to performance sheet that has the 95 degree ambient temperature for steam power augmentation. However, attached please find a data sheet for steam power augmentation at an ambient temperature of 80 degrees F, at 60% relative humidity with turbine inlet fogging at 95% fogger efficiency. The turbine compressor inlet temperature would be cooled by the fogger by about 9.5 degrees F or very close to a 70 degree F ambient temperature without fogging. Since performance in linear, the 95 degree ambient and 70 degree ambient (80 degree ambient with fogging) would provide the performance characteristics for the machine under steam augmentation.

The modeling was conducted with the margins provided for mass flow with the parameters presented in Tables 2-1 through 2-7 of the PSD attachment in the application. While the margin in mass flow increases flow rate, the modeling was conducted using the range of estimated machine performance and temperatures. Also, the emissions increase proportionally. The conditions modeled were at loads of 50%, 75% and 100% at ambient temperatures of 35 degree F, 59 degree F and 95 degree F. This provides a wide range of estimated turbine performance. The maximum impacts for the project were for oil firing. For SO_2 and NO_x the maximum impacts were at 75% load and 59 degree F, while for PM and CO the maximum impacts were at 50% load and 95 degree F. All impacts were at least 9 times lower than the Significant Impact Levels. Refer to Table 6-6 in PSD attachment of the application.

Let me know if you need more information. Any assistance in getting a draft permit out ASAP is appreciated.

Regards, Ken

-----Original Message-----
From: Jeff Koerner TAL 850/414-7268 GIC 069
[mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Friday, April 14, 2000 8:12 AM
To: Ken Kosky
Cc: Alvaro Linero TAL; Rich Piper
Subject: FPL Martin Plant - Peaking Units
Sensitivity: Confidential

FPL Martin Plant Gas fuel Steam Power Augmentation with Fogger at 80 degF

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	80.
Fogger Status		On
Fogger Effectiveness	%	95
Output	kW	165,000.
Heat Rate (LHV)	Btu/kWh	9,410.
Heat Cons. (LHV) X 10^6	Btu/h	1,552.7
Auxiliary Power	kW	560
Output Net	kW	164,440.
Heat Rate (LHV) Net	Btu/kWh	9,440.
Exhaust Flow X 10^3	lb/h	3444. → 2286644 acfm
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	933.1

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	76.
CO	ppmvd	15
CO	lb/h	47.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88
Nitrogen	73.38
Oxygen	12.19
Carbon Dioxide	3.86
Water	9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/24/2000 17:58 FPL Martin gas BL stm aug 80 fogg.dat

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 10-Apr-2000 03:53pm
From: Kosky, Ken
KKosky@GOLDER.com
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)
CC: rich_piper (rich_piper@fpl.com)
CC: Wood, Janet (jwood@golder.com)

Subject: Re: FPL Martin Plant - Request for Additional Information No. 2

Jeff: Attached is the information requested. I'll send the original out via US mail tomorrow. Please call if you have further questions or you have problems in the files being transmitted. Regards, Ken

-----Original Message-----
From: Jeff Koerner TAL 850/414-7268 GIC 069
[mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Thursday, April 06, 2000 12:17 PM
To: Ken Kosky
Subject: FPL Martin Plant - Request for Additional Information No. 2
Sensitivity: Confidential

April 10, 2000

Jeffery F. Koerner, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

RE: Request for Additional Information
DEP File No. 0850001-001-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Jeff:

This correspondence provides the additional information requested in the Department's April 6, 2000 letter concerning FPL's Martin Peaking Project. The information is provided in the same format as requested.

1. Question: Your response included the GE data sheets for gas firing, but only for a compressor inlet temperature of 75° F. Please provide the GE data sheets for the full range of ambient (inlet) temperatures of 35° F, 59° F, 75° F, and 95° F. Also, a reference was made to recent permits for Fort Myers and Sanford Re-powering projects. It is my understanding that these projects did not require BACT determinations.

Response: Attached please find the GE Data sheets requested. The FPL Fort Myers Repowering Project was not required to under go PSD review and therefore, BACT review was not required. The FPL Sanford Repowering Project was required to under go PSD and BACT review for VOCs.

2. The "high power mode" described in the application represents two separate operating scenarios: steam injection for power augmentation, and elevating the combustion reference temperature just before the gas turbine blades to increase power performance. Combined with the planned peaking operation of these units, the high power modes of operation are expected to increase the designed mass flow rate by 5% due to higher fuel consumption as well as 6% due to overall degradation as a result of this operation. The application reflects this by an 11% increase in the mass flow rate over that specified by General Electric for normal operation. Are these statements accurate?

Response: The "higher power mode" is used to characterize the two modes of operation. One set of performance and emission curves were developed from the GE data to describe an envelope for these "higher power modes". There are slight differences for each mode of operation as can be seen from the GE performance curves. Under steam augmentation, mass flow and heat input increase with concomitant increases in power. Under peak mode, the mass flow remains about the same but the volume flow increases due to higher firing temperature resulting from higher heat input. The 11% increase in mass flow was used as a means for conservatively estimating mass emissions in lb/hr due to the turbine performing better than expected (i.e., higher mass flow for the same heat input) and degradation (i.e., lower heat rate with wear of turbine components potentially allowing higher heat input and mass flow). As mentioned in the previously, the only effect in the analyses presented in the application is that the emissions are conservatively estimated for both the modeling analysis and the BACT evaluation.

3. Question: FPL states that the two proposed combustion turbines for this project are not "Martin 5 and 6" as identified in FPL's "10 Year Power Plant Site Plan" dated April of 1999. Is this correct? The purpose of this question is to notify the applicant that the permit will be conditioned such that modifying the proposed project to incorporate combined cycle operation will trigger a new PSD review as if the project has never been built. In particular, CO and NOx controls must be reevaluated at that point because the constraints that lead to the BACT determinations for these permits will be removed.

Response: The GE Frame 7FA turbines designated for this project are not associated with Martin 5 and 6 as described in FPL's Ten Year Power Plant Site Plan and have an in-service date of 2006 and 2007, respectively. The combustion turbines associated with the Martin Peaking Project are being installed much sooner to increase the reserve margin suggested by the Florida Public Service Commission last fall. It is recognized that if these units are subsequently converted to combined cycle, that PSD including BACT review may be applicable.

4. No additional questions. (No response required.)

5. Question: Your response indicates a revised cost analysis for SCR that was omitted. Please submit.

Response: Attached please find the cost tables. These were inadvertently left out of the letter sent with the Department.

6. Your response indicates a revised cost analysis for an oxidation catalyst that was omitted. Please submit.

Response: Attached please find the cost tables. These were inadvertently left out of the letter sent with the Department.

7. No additional questions regarding the air quality analysis. (No response required.)

Please call if there are any technical questions on the application. Your assistance is always appreciated.

Sincerely,

Kennard F. Kosky, P.E.
Principal
Enclosures
cc: Rich Piper, FPL

Table B-3 rev-1. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$2,835,000	Vendor Estimate
Ammonia Storage Tank	$136,500	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$0	Additional NO_x Monitor and System
Taxes	$0	6% of SCR Associated Equipment and Catalyst
Freight	$141,750	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,180,008	
Direct Installation Costs		
Foundation and supports	$254,401	8% of TDCC;OAQPS Cost Control Manual
Handling & Erection	$445,201	14% of TDCC;OAQPS Cost Control Manual
Electrical	$127,200	4% of TDCC;OAQPS Cost Control Manual
Piping	$63,600	2% of TDCC;OAQPS Cost Control Manual
Insulation for ductwork	$31,800	1% of TDCC;OAQPS Cost Control Manual
Painting	$31,800	1% of TDCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs	$974,002	
Total Capital Costs (TCC)	$4,154,010	Sum of TDCC and TDIC
Indirect Costs		
Engineering	$318,001	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$159,000	5% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$318,001	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Start-up	$63,600	2% of Total Direct Capital Costs; OAQPS Cost Control Manual
Performance Tests	$31,800	1% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contingencies	$95,400	3% of Total Direct Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost	$1,035,802	

Total Direct, Indirect and Capital Costs	$5,189,813	Sum of Capital Costs

Table B-4 rev -1. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$55,220	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$19,690	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$676,028	
Energy Costs		
Electrical	$37,968	80kW/h for SCR & 200kW/h for cooling @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$207,224	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$245,192	
Indirect Annual Costs		
Overhead	$46,049	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$51,898	1% of Total Capital Costs
Insurance	$51,898	1% of Total Capital Costs
Annualized Total Direct Capital	$569,841	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$719,686	
Total Annualized Costs	$1,640,906	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$12,943	NO_x Reduction Only
	$23,932	Net Emission Reduction

Table B-6 rev-1. Direct and Indirect Capital Costs for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
CO Associated Equipment	$843,000	Vendor Quote
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$84,300	10% of Associated Equipment
Sales Tax	$0	6% of Associated Equipment/Catalyst
Freight	$42,150	5% of Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$1,036,208	
<u>Direct Installation Costs</u>		
Foundation and supports	$82,897	8% of TDCC;OAQPS Cost Control Manual
Handling & Erection	$145,069	14% of TDCC;OAQPS Cost Control Manual
Electrical	$41,448	4% of TDCC;OAQPS Cost Control Manual
Piping	$20,724	2% of TDCC: OAQPS Cost Control Manual
Insulation for ductwork	$10,362	1% of TDCC;OAQPS Cost Control Manual
Painting	$10,362	1% of TDCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$315,862	
Total Capital Costs	$1,352,070	Sum of TDCC, TDIC and RCC
<u>Indirect Costs</u>		
Engineering	$103,621	10% of TDCC; OAQPS Cost Control Manual
Construction and Field Expense	$51,810	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$103,621	10% of TDCC; OAQPS Cost Control Manual
Start-up	$20,724	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$10,362	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$31,086	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$321,224	
Total Direct, Indirect and Capital Costs (TDICC)	$1,673,295	Sum of TCC and TInCC

Table B-7 rev-1. Annualized Cost for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$214,333	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$28,365	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,496	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$257,371	
Energy Costs		
Heat Rate Penalty	$82,890	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu additional fuel costs
Total Energy Costs (TDEC)	$82,890	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,733	1% of Total Capital Costs
Insurance	$16,733	1% of Total Capital Costs
Annualized Total Direct Capital	$183,728	10.98 Capital Recovery Factor of 7% over 15 yrs % times sum of TDICC
Total Indirect Annual Costs	$221,499	
Total Annualized Costs	$561,759	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$7,595	Simple CycleCombustion Turbine
	$8,496	Net Emission Reduction

FPL Martin Plant **Gas Fuel**
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,200.	136,700.	91,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,855.	11,820.
Heat Cons. (LHV) X 10^6	Btu/h	1,673.5	1,347.2	1,076.8
Auxiliary Power	kW	560	560	560
Output Net	kW	181,640.	136,140.	90,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,900.	11,890.
Exhaust Flow X 10^3	lb/h	3706.	2979.	2456.
Exhaust Temp.	Deg F.	1095.	1122.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	991.1	831.5	725.6

2,460,595 acfm

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	61.	49.	39.
CO	ppmvd	9.	9.	9.
CO	lb/h	30.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.90	0.90
Nitrogen	75.07	75.10	75.21
Oxygen	12.60	12.67	12.99
Carbon Dioxide	3.88	3.85	3.70
Water	7.56	7.49	7.21

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions

are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:44 FPL Martin gas BL LOAD rge 35

FPL Martin Plant Gas Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	173,000.	129,800.	86,500.
Heat Rate (LHV)	Btu/kWh	9,250.	10,000.	12,050.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.3	1,298.	1,042.3
Auxiliary Power	kW	560	560	560
Output Net	kW	172,440.	129,240.	85,940.
Heat Rate (LHV) Net	Btu/kWh	9,280.	10,040.	12,130.
Exhaust Flow X 10^3	lb/h	3539.	2888.	2396.
Exhaust Temp.	Deg F.	1116.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	951.8	807.5	707.9

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.90	0.90
Nitrogen	74.42	74.46	74.58
Oxygen	12.44	12.57	12.90
Carbon Dioxide	3.87	3.81	3.66
Water	8.39	8.27	7.97

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions

are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:45 FPL Martin gas BL LOAD rge 59

FPL Martin Plant Gas Fuel

LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	150,300.	112,800.	75,200.
Heat Rate (LHV)	Btu/kWh	9,630.	10,550.	12,770.
Heat Cons. (LHV) X 10^6	Btu/h	1,447.4	1,190.	960.3
Auxiliary Power	kW	560	560	560
Output Net	kW	149,740.	112,240.	74,640.
Heat Rate (LHV) Net	Btu/kWh	9,670.	10,600.	12,870.
Exhaust Flow X 10^3	lb/h	3257.	2694.	2267.
Exhaust Temp.	Deg F.	1143.	1170.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	881.8	761.2	667.1

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	53.	43.	35.
CO	ppmvd	9.	9.	9.
CO	lb/h	26.	22.	18.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.6	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.87	0.87
Nitrogen	73.16	73.20	73.34
Oxygen	12.27	12.41	12.80
Carbon Dioxide	3.78	3.72	3.54
Water	9.92	9.80	9.45

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions

are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:56 FPL Martin gas BL LOAD rge 95

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	190,500.	142,900.	95,200.
Heat Rate (LHV)	Btu/kWh	9,945.	10,550.	12,500.
Heat Cons. (LHV) X 10_6	Btu/h	1,894.5	1,507.6	1,190.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	189,110.	141,510.	93,810.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,650.	12,690.
Exhaust Flow X 10_3	lb/h	3862.	3024.	2487.
Exhaust Temp.	Deg F.	1074.	1121.	1168.
Exhaust Heat (LHV) X 10_6	Btu/h	1042.6	868.7	752.4
Water Flow	lb/h	130,930.	94,620.	66,770.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	334.	263.	206.
CO	ppmvd	20.	24.	35.
CO	lb/h	68.	65.	77.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	98.0	78.0	61.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	5.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.87
Nitrogen	71.79	72.10	72.73
Oxygen	11.19	11.22	11.76
Carbon Dioxide	5.56	5.60	5.35
Water	10.60	10.23	9.29

SITE CONDITIONS

Elevation	ft.	45.0

Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:00FPL Martin dis load rge 35

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	181,800.	136,400.	90,900.
Heat Rate (LHV)	Btu/kWh	9,960.	10,620.	12,670.
Heat Cons. (LHV) X 10^6	Btu/h	1,810.7	1,448.6	1,151.7
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	180,410.	135,010.	89,510.
Heat Rate (LHV) Net	Btu/kWh	10,040.	10,730.	12,870.
Exhaust Flow X 10^3	lb/h	3683.	2936.	2435.
Exhaust Temp.	Deg F.	1098.	1137.	1182.
Exhaust Heat (LHV) X 10^6	Btu/h	1000.7	841.4	734.9
Water Flow	lb/h	120,720.	86,500.	61,390.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	253.	199.
CO	ppmvd	20.	24.	34.
CO	lb/h	65.	61.	73.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	94.0	75.0	60.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	3.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.88
Nitrogen	71.31	71.72	72.33
Oxygen	11.06	11.21	11.76
Carbon Dioxide	5.56	5.54	5.27
Water	11.21	10.68	9.77

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68

Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:01 FPL Martin dis load rge 59

FPL MARTIN PLANT **Distillate Fuel**
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	160,600.	120,500.	80,300.
Heat Rate (LHV)	Btu/kWh	10,190.	11,010.	13,220.
Heat Cons. (LHV) X 10^6	Btu/h	1,636.5	1,326.7	1,061.6
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	159,210.	119,110.	78,910.
Heat Rate (LHV) Net	Btu/kWh	10,280.	11,140.	13,450.
Exhaust Flow X 10^3	lb/h	3376.	2758.	2323.
Exhaust Temp.	Deg F.	1131.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	926.3	793.5	695.9
Water Flow	lb/h	98,570.	70,300.	49,100.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	289.	232.	183.
CO	ppmvd	20.	24.	36.
CO	lb/h	59.	57.	74.
UHC	ppmvw	7.	7.	7:
UHC	lb/h	13.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	6.5	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	85.0	69.0	55.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	7.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	70.52	70.99	71.61
Oxygen	11.00	11.25	11.86
Carbon Dioxide	5.46	5.38	5.07
Water	12.18	11.54	10.60

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68

Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:03 FPL Martin dis load rge 95

FPL Martin Plant Gas fuel with Steam Power Augmentation
Augmentation only permitted above 59 degF
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE
Ambient Temp.	Deg F.	35.	95.
Ambient Relative Humid.	%	20.0	50.0
Fuel Type		Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835
Fuel Temperature	Deg F	290	290
Output	kW	180,400.	165,100.
Heat Rate (LHV)	Btu/kWh	9,245.	9,265.
Heat Cons. (LHV) X 10^6	Btu/h	1,667.8	1,529.7
Auxiliary Power	kW	560	560
Output Net	kW	179,840.	164,540.
Heat Rate (LHV) Net	Btu/kWh	9,270.	9,300.
Exhaust Flow X 10^3	lb/h	3706.	3372.
Exhaust Temp.	Deg F.	1095.	1130.
Exhaust Heat (LHV) X 10^6	Btu/h	991.6	927.1
Steam Flow	lb/h	0.	110,260.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	12
NOx AS NO2	lb/h	61.	82
CO	ppmvd	9.	15.
CO	lb/h	30.	44.
UHC	ppmvw	7.	7.
UHC	lb/h	15.	14.
VOC	ppmvw	1.4	1.4
VOC	lb/h	3.	2.8
Particulates	lb/h	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.83
Nitrogen	75.07	69.28
Oxygen	12.60	11.20
Carbon Dioxide	3.88	3.80
Water	7.56	14.89

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/24/2000 17:49 FPL Martin gas BL stm aug 35_95.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	35.
Output	kW	190,300.
Heat Rate (LHV)	Btu/kWh	9,080.
Heat Cons. (LHV) X 10^6	Btu/h	1,727.9
Auxiliary Power	kW	560
Output Net	kW	189,740.
Heat Rate (LHV) Net	Btu/kWh	9,110.
Exhaust Flow X 10^3	lb/h	3713.
Exhaust Temp.	Deg F.	1109.
Exhaust Heat (LHV) X 10^6	Btu/h	1015.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	105.
CO	ppmvd	9.
CO	lb/h	30.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	75.00
Oxygen	12.39
Carbon Dioxide	3.98
Water	7.74

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:49 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	59.
Output	kW	179,500.
Heat Rate (LHV)	Btu/kWh	9,225.
Heat Cons. (LHV) X 10^6	Btu/h	1,655.9
Auxiliary Power	kW	560
Output Net	kW	178,940.
Heat Rate (LHV) Net	Btu/kWh	9,250.
Exhaust Flow X 10^3	lb/h	3541.
Exhaust Temp.	Deg F.	1139.
Exhaust Heat (LHV) X 10^6	Btu/h	983.3

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	101.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	74.34
Oxygen	12.20
Carbon Dioxide	3.98
Water	8.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:46 FPL MARTIN PLANT Peak gas 59 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	95.
Output	kW	156,100.
Heat Rate (LHV)	Btu/kWh	9,595.
Heat Cons. (LHV) X 10^6	Btu/h	1,497.8
Auxiliary Power	kW	560
Output Net	kW	155,540.
Heat Rate (LHV) Net	Btu/kWh	9,630.
Exhaust Flow X 10^3	lb/h	3238.
Exhaust Temp.	Deg F.	1172.
Exhaust Heat (LHV) X 10^6	Btu/h	910.7

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	91.
CO	ppmvd	9.
CO	lb/h	26.
UHC	ppmvw	7.
UHC	lb/h	13.
VOC	ppmvw	1.4
VOC	lb/h	2.6
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88
Nitrogen	73.06
Oxygen	11.99
Carbon Dioxide	3.91
Water	10.16

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by

algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 95 dry.dat

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 6, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information No. 2
DEP File No. 0850001-008-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Mr. Lindsay:

On March 24, 2000, the Department received a response from Golder Associates to our request for additional information regarding the new project for the FPL Martin Plant. The application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form. The original numbering of the questions has been retained.

1. Your response included the GE data sheets for gas firing, but only for a compressor inlet temperature of 75° F. Please provide the GE data sheets for the full range of ambient (inlet) temperatures of 35° F, 59° F, 75° F, and 95° F. Also, a reference was made to recent permits for Fort Myers and Sanford Re-powering projects. It is my understanding that these projects did not require BACT determinations.

2. The "high power mode" described in the application represents two separate operating scenarios: steam injection for power augmentation, and elevating the combustion reference temperature just before the gas turbine blades to increase power performance. Combined with the planned peaking operation of these units, the high power modes of operation are expected to increase the designed mass flow rate by 5% due to higher fuel consumption as well as 6% due to overall degradation as a result of this operation. The application reflects this by an 11% increase in the mass flow rate over that specified by General Electric for normal operation. Are these statements accurate?

3. FPL states that the two proposed combustion turbines for this project are not "Martin 5 and 6" as identified in FPL's "10 Year Power Plant Site Plan" dated April of 1999. Is this correct? The purpose of this question is to notify the applicant that the permit will be conditioned such that modifying the proposed project to incorporate combined cycle operation will trigger a new PSD review as if the project has never been built. In particular, CO and NOx controls must be reevaluated at that point because the constraints that lead to the BACT determinations for these permits will be removed.

4. No additional questions.

5. Your response indicates a revised cost analysis for SCR that was omitted. Please submit.

6. Your response indicates a revised cost analysis for an oxidation catalyst that was omitted. Please submit.

7. No additional questions regarding the air quality analysis.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Cleve Holladay, meteorologist, at 850/921-8986.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Enclosure

cc: Mr. John M. Lindsay, FPL
Mr. Richard G. Piper, FPL
Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Z 031 391 937

US Postal Service
Receipt for Certified Mail
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PS Form 3800, April 1995

- 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:
John Lindsay, Plant Gen. Mgr
FP&L - Martin Plant
PO Box 176
Indiantown, Fl
34956

A. Received by *(Please Print Clearly)*

B. Date of Delivery 4-10-00

C. Signature
X

☐ Agent
☐ Addressee

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

2. Article Number *(Copy from service label)* Z 031 391 937

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Martin 5

Post-it® Fax Note 7671	Date 4/6/00	# of pages ▶
To Ken Kosky	From	
Co./Dept. Golder Assts.	Co.	
Phone # 352-336-5600	Phone #	
Fax # 352-336-6603	Fax #	

(2)	**Capacity**	
	a. Summer	419 MW
	b. Winter	448 MW
(3)	**Technology Type:**	Combined Cycle
(4)	**Anticipated Construction Timing**	
	a. Field construction start-date:	2002
	b. Commercial In-service date:	2006
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	Distillate
(6)	**Air Pollution and Control Strategy:**	LNB (Low Nox Burners)
(7)	**Cooling Method:**	CP (Cooling Pond)
(8)	**Total Site Area:**	11,179 Acres
(9)	**Construction Status:**	P (Planned)
(10)	**Certification Status:**	P (Planned)
(11)	**Status with Federal Agencies:**	P (Planned)
(12)	**Projected Unit Performnace Data:**	
	Planned Outage Factor (POF):	3%
	Forced Outage Factor (FOF):	1%
	Equivalent Availability Factor (EAF):	96%
	Resulting Capacity Factor (%):	96% (First Year)
	Average Net Operating Heat Rate (ANHOR):	6,081 Btu/kWh
(13)	**Projected Unit Financial Data ***	
	Book Life (Years):	30 years
	Total Installed Cost (In-Service Year $/kW):	590
	Direct Construction Cost ($/kW):	464
	AFUDC Amount ($/kW):	54
	Escalation ($/kW):	72
	Fixed O&M ($/kW -Yr.):	12.02 (1998$)
	Variable O&M ($/MWH):	0.67 (1998$)
	K Factor:	1.6480

* Fixed O&M cost includes capital replacement.

From FPL's 10 Year Power Plant Site Plan April 1999

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Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Martin 6		
(2)	**Capacity**		
	a. Summer	419 MW	
	b. Winter	448 MW	
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	LNB	(Low Nox Burners)
(7)	**Cooling Method:**	CP	(Cooling Pond)
(8)	**Total Site Area:**	11,179	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performnace Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,081	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (In-Service Year $/kW):	604	
	Direct Construction Cost ($/kW):	464	
	AFUDC Amount ($/kW):	55	
	Escalation ($/kW):	84	
	Fixed O&M ($/kW-Yr.):	12.02	(1998$)
	Variable O&M ($/MWH):	0.67	(1998$)
	K Factor:	1.6480	

* Fixed O&M cost includes capital replacement.

Projected Capacity Changes and Reserve Margins for FPL (1)

Year		Net Capacity Changes (MW) Summer (2)	Winter (3)	FPL Reserve Margi[n] Summer	Wi[nter]
1999	Changes to existing plants	239	80	17%	21
2000	Changes to existing plants	75	75	15%	19
2001	Changes to existing plants	20	23	16%	18
	Changes to existing purchases	(9)	---		
	Ft. Myers Repowering:Initial Phase (4)	201	182		
2002	Ft. Myers Repowering:Second Phase	725	920	20%	22
	Changes to existing plants	---	30		
	Changes to existing purchases	---	(9)		
	Sanford Repowering:Initial Phase (4),(5)	202	182		
2003	Sanford Repowering:Second Phase (5)	725	919	23%	25
2004	Changes to existing purchases	(10)	(10)	21%	22
2005	Changes to existing purchases	---	---	19%	20
2006	Martin Combined Cycle No.5	419	448	19%	19
	Changes to existing purchases	(133)	(133)		
2007	Martin Combined Cycle No.6	419	448	19%	20
2008	Unsited Combined Cycle	419	448	20%	20
	TOTALS=	*3,292*	*3,603*		

Note:

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Summer values are values for August of year shown.

(3) Winter values are values for January of year shown.

(4) The initial phase of the repowering projects consists of the introduction of combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and existing steam turbines.

(5)The values shown above reflect FPL's 1998 IRP which identified that Sanford units #3 and #4 would be repowered. At the time of publication of this document, subsequent to FPL's 1998 IRP, FPL is reexamining its Sanford repowering plan. This reexamination is based on newly developed technical information which focuses on whether it would be more advantageous to repower units #4 and #5 rather than units #3 and #4. Such a change in the Sanford repowering plan would add approximately 240 MW summer capability from the Sanford site beyond what would be gained from repowering units #3 and #[4]. If such a change is made to the Sanford repowering plan during 1999, it will be communicated to the appropriate state agenci[es] and reflected in FPL's 2000 Site Plan filing.

Table ES.1

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 30-Mar-2000 02:38pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Cleve Holladay TAL (HOLLADAY_C)

Subject: FPL Martin Plant - Combustion Turbine Project

Cleve,

I checked the file for this project. We sent a letter requesting additional information on March 10th. The letter indicated that we did not receive the modeling files until March 3rd and that we would ask those questions within 30 days of March 3rd. Day 30 falls on April 2nd, a Sunday, so I guess you get until Monday, April 3rd. Golder did respond to my questions regarding the equipment on March 24th. Let me know if we need to send out another request for additional information.

Thanks.

Jeff

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

March 23, 2000

9937614A/01

A.A. Linero, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

RECEIVED
MAR 24 2000
BUREAU OF AIR REGULATION

RE: REQUEST FOR ADDITIONAL INFORMATION
DEP FILE NO. 0850001-001-AC (PSD-FL-286)
TWO SIMPLE CYCLE, 170 MW COMBUSTION TURBINES IN MARTIN COUNTY

Dear Al:

This correspondence provides information requested in the Department's March 20 2000 letter concerning FPL's Martin Peaking Project. The information is provided in the same format as requested.

1. Question: The application identifies the General Electric Frame 7FA as the gas turbine model chosen for this project with DLN 2.6 combustors. Please provide manufacturer information supporting the proposed CO and NO_x emissions standards of 10.5 ppmvd and 15 ppmvd, respectively. The Department is aware of other projects that plan to install this model turbine with standards of 9 ppmvd for both CO and NO_x.

Response: Attached are GE data sheets regarding the performance of the simple cycle turbines. These data were used in the development of emissions in Appendix A of the PSD application. A NO_x emission limit of 10.5 ppmvd corrected to 15 percent O_2 is proposed for baseload operation to provide margin due to the peaking nature of the turbines. It is our understanding that the Department has approved similar limits for the simple cycle peaking turbines for Jacksonville Electric Authority and the Tampa Electric Company. In addition, the amount of hours proposed for the Martin project considered the Department's previous determinations. The combination of 10.5 ppmvd corrected to 15 percent O_2 for 2,390 hours of baseload gas fired-operation, 15 ppmvd corrected to 15 percent O_2 for 500 hours of higher power modes (HPM) gas-fired operation and 42 ppmvd corrected to 15 percent O_2 for 500 hours of distillate oil firing, results in lower annual emissions than many previous projects. For example, the proposed limits for the Martin Peaking Project result in 207.5 tons/year of NO_x. In contrast, 9 ppmvd corrected to 15 percent O_2 for 2,390 hours of higher power mode gas-fired operation and 42 ppmvd corrected to 15 percent O_2 for 1,000 hours of distillate oil firing (which has been approved by the Department for previous projects) results in annual potential NO_x emissions of 254 tons/year.

The proposed emission limits for CO are 12 ppmvd for baseload gas-fired operation and 15 ppmvd for HPM. The proposed CO limit for baseload operation is identical to that approved by the Department for the Fort Myers and Sanford Repowering Projects.

2. Question: Please explain the statement on page 2-2 regarding, "... degradation when the units operate over time and performance improvements beyond that provided by the manufacturer's guarantee. In particular, the combustion turbine emission estimates account for 5 percent higher power output and 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine."

Response: The machine performance margin was added since the turbines may perform better than projected. Obviously, the manufacturer must meet minimum performance, which directly relates to mass flow. If the machine performs above the guarantee level, mass flow will increase with a concomitant increase in emissions (at the same concentration). This may also be true as the machine ages and heat rate deteriorates. With a higher heat rate, more fuel and mass flow is needed for the same amount of generation. This margin also provides conservative estimates for modeling purposes. It is recognized that the Department BACT determinations are based on concentrations (i.e., ppmvd corrected to 15 percent O_2 for NO_x and ppmvd for CO).

3. Question: When these units are converted to combined cycle operation as detailed in the "Ten Year Power Plant Site Plan, 1999 – 2008", what additional control equipment does FPL plan to install for the control of CO and NO_x emissions?

Response: The proposed project is planned as a simple cycle project and it is not currently intended that these units be converted to combined cycle. The units referred to in the Ten Year Site Plan are Martin Units 5 and 6, which are combined cycle units identified in the original certification of Martin Unit 3 and 4. If in the future FPL does decide to convert the peaking units to combined cycle, FPL assumes that the BACT determination would need to be revisited for base-loaded (i.e. 8,760 hours) units.

4. Question: According to the manufacturer, how many minutes of startup does it take the unit to reach 50% of base load? How many minutes does it take to shutdown the unit? Please estimate the number of startups in a year based on the proposed maximum 3390 hours per year of operation. The Department plans to address excess emissions from startup and shutdown in the BACT determination.

Response: FPL projects that about 250 starts per unit would be typical for these turbines in peaking service. Unlike combined cycle projects, these peaking turbines can achieve loads greater the 50 percent in about 30 minutes or less. Thus, emission will be minimized and the excess emissions provided in Rule 62-210.700 are sufficient for the operation of these units.

5. Please revise the SCR cost analysis based on the following:

   - Question: Please explain the $50,000 cost for "additional NO_x monitor and system"

   Response: This cost was added for an inlet monitor to better regulate performance of the "hot" SCR system. Without an additional monitor, catalyst degradation would only be known by the amount of ammonia used and NO_x emissions. The effect of this cost was recalculated on the attached revised cost estimates.

- Question: Please explain the 6% tax. Is this Florida sales tax? Does this apply in all cases? Are deductions available for air pollution control equipment?

Response: Sales and other taxes may be applicable to the SCR equipment and were included as a 6 percent charge. The affect of this cost was recalculated on the attached revised cost estimates.

- Question: The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.

Response: See attached revised cost calculations. With this recalculation and those previously noted above, the revised cost effectiveness is $12,943 per ton of NO_x removed. The initial estimate was $13,636 per ton of NO_x removed.

- Question: Please show the calculation for the estimated "tons" of ammonia needed.

Response: Ammonia usage was based on a NO_x removal of 61.1 percent at the maximum potential emissions of 207.5 tons/year and adding 10 percent for ammonia slip. The calculation is: 207.5 tons/year x 0.611 x 17 MW of NH_3 /46 MW of NO_x x 1.10 = 51.5 tons NH_3. This is pure ammonia while the cost estimate is based on aqueous ammonia at 28 percent ammonia in water. The aqueous ammonia usage is 51.54 /0.28 = 184.1 tons/year. Please note that the 10 percent margin on ammonia only account for 4.7 tons/year of ammonia slip, while the vendor guarantee of 9 ppmvd corrected to 15 percent O_2 is 47 tons/year.

- Question: The vendor quote is based on a turbine exhaust flow that includes the 11% "degradation". Doesn't this tend to inflate catalyst costs, ammonia costs, and the overall cost estimate?

Response: As described in response to Question 2, emissions at this level may occur. The effect would have a marginal effect on the annualized cost. Indeed, increasing emissions would directly lower the cost effectiveness since it is inversely proportional. In this case higher emissions would have more of an effect (i.e., increase cost effectiveness by about $1,400 per ton of NO_x removed) than increased costs associated with ammonia (i.e., lower cost effectiveness by less than $100 per ton of NO_x removed).

- Question: On the first page of the Engelhard Corporation vendor quote, the system design basis indicates a similar quote for the Westinghouse Model 501D and the General Electric Model 7FA. It also suggests that the costs were based on an ammonia slip of 9 ppm for the 501D and 5 ppm for the 7FA. Please explain.

Response: The vendor information provided for the Martin Peaking Project in the application was specific for the GE Frame 7FA simple cycle turbine. This was part of information provided by the Engelhard Corporation for various turbine configurations (simple cycle and combined cycle) and manufacturers (both GE and Siemens-Westinghouse) that Golder Associates is currently working.

6. Please revise the oxidation catalyst cost analysis based on the following:

   - Question: What additional "instrumentation" ($84,300) will be added as a result of the oxidation catalyst?

   Response: A continuous emission monitor (CEM) system for CO would be necessary to determine CO emissions from the oxidation catalyst. The Department's previous permits for simple cycle projects have not required CO CEM system.

   - Question: If necessary, revise this cost estimate with regard to the sales tax question in #5.

   Response: Sales and other taxes may be applicable to the SCR equipment and were included as a 6 percent charge. The affect of this cost was recalculated on the attached revised cost estimates.

   - Question: The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.

   Response: See attached revised cost calculations. With this recalculation and those previously noted above, the revised cost effectiveness is $7,595 per ton of NO_x removed. The initial estimate was $7,918 per ton of NO_x removed.

   - Question: The "heat rate penalty" includes a 0.2% MW output loss and a $3/mmBTU of additional fuel costs. Please explain why this wouldn't be considered "double-counting".

   Response: These costs reflect two different and distinct costs that would be incurred by a reduction in power. First, less power would be produced and there would be lost revenue as a result. This cost accounts for 56.4 percent of the heat rate penalty and is based on $40/MWhr at 0.2% of 172.44 MW. Second, the heat rate (Btu/kWhr) is reduced proportionally, which results in proportionally higher fuel costs. This cost is 43.6 percent of the heat rate penalty and is based on gas cost of $3/mmBtu and a heat rate reduction of 0.2% using 1,776 mmBtu/hr.

Please call if there are any technical questions on the application. Your assistance is always appreciated.

Sincerely,

Robert C. McCann for

Kennard F. Kosky, P.E.
Principal

KFK/jkw

Enclosures

cc: Rich Piper, FPL

cc: J. Koerner, BAR
R. Piper, FP&L
SED
EPA
NPS
B. Oven, PPS

FPL Martin Plant Steam Power Augmentation on Gas
Guarantee Delta from Baseload Dry
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,835
Fuel Temperature	Deg F	290
Output	kW	178,700.
Heat Rate (LHV)	Btu/kWh	9,060.
Heat Cons. (LHV) X 10^6	Btu/h	1,619.
Auxiliary Power	kW	560
Output Net	kW	178,140.
Delta Output Net	kW	+15,000
Heat Rate (LHV) Net	Btu/kWh	9,090.
Delta Heat Rate (LHV) Net	Btu/kWh	-320
Exhaust Flow X 10^3	lb/h	3538.
Delta Exhaust Flow X 10^3	lb/h	+120.
Exhaust Temp.	Deg F.	1115.
Delta Exhaust Temp.	Deg F.	-13
Exhaust Heat (LHV) X 10^6	Btu/h	968.8
Steam Flow	lb/h	115,670.

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	74.6
CO	ppmvd	15.
CO	lb/h	46.7.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates(TSP)	lb/h	9.0
Particulates(PM10)	lb/h	18.0
Opacity		10%

EXHAUST ANALYSIS

	% VOL.
Argon	0.84
Nitrogen	69.97
Oxygen	11.33
Carbon Dioxide	3.83
Water	14.04

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel. IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 02/18/2000 12:16 FPL Martin gas BL stm aug 75 guar delta.dat

FPL MARTIN PLANT Peak Firing
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	75.
Output	kW	169,500.
Heat Rate (LHV)	Btu/kWh	9,370.
Heat Cons. (LHV) X 10^6	Btu/h	1,588.2
Auxiliary Power	kW	560
Output Net	kW	168,940.
Heat Rate (LHV) Net	Btu/kWh	9,400.
Exhaust Flow X 10^3	lb/h	3413.
Exhaust Temp.	Deg F.	1152.
Exhaust Heat (LHV) X 10^6	Btu/h	952.2

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	97.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates (TSP)	lb/h	9.0
Particulates (PM10)	lb/h	18.0

EXHAUST ANALYSIS

	% VOL.
Argon	0.89
Nitrogen	73.80
Oxygen	12.12
Carbon Dioxide	3.95
Water	9.25

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 75 dry.dat

FPL Martin Plant Gas Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%
Ambient Temp.	Deg F.	75.	75.	75.	75.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290	290
Output	kW	163,700.	122,800.	81,900.	40,900.
Heat Rate (LHV)	Btu/kWh	9,380.	10,190.	12,330.	17,110.
Heat Cons. (LHV) X 10^6	Btu/h	1,535.5	1,251.3	1,009.8	699.8
Auxiliary Power	kW	560	560	560	560
Output Net	kW	163,140.	122,240.	81,340.	40,340.
Heat Rate (LHV) Net	Btu/kWh	9,410.	10,240.	12,410.	17,350.
Exhaust Flow X 10^3	lb/h	3418.	2803.	2336.	2130.
Exhaust Temp.	Deg F.	1128.	1153.	1195.	1028.
Exhaust Heat (LHV) X 10^6	Btu/h	921.1	786.3	692.2	531.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	77.
NOx AS NO2	lb/h	56.	45.	36.	213.
CO	ppmvd	9.	9.	9.	61.
CO	lb/h	28.	23.	19.	119.
UHC	ppmvw	7.	7.	7.	28.
UHC	lb/h	14.	11.	9.	33.
VOC	ppmvw	1.4	1.4	1.4	5.6
VOC	lb/h	2.8	2.2	1.8	6.6
Particulates	lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.88	0.89	0.90
Nitrogen	73.88	73.93	74.04	74.69
Oxygen	12.36	12.49	12.83	14.72
Carbon Dioxide	3.84	3.78	3.62	2.75
Water	9.04	8.92	8.62	6.95

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:54 FPL Martin gas BL LOAD rge 75

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG72[illegible](FA)

Load Condition		BASE	75%	50%	25%
Ambient Temp.	Deg F.	75.	75.	75.	75.
Fuel Type		Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78	1.78
Output	kW	173,900.	130,500.	87,000.	43,500.
Heat Rate (LHV)	Btu/kWh	10,020.	10,750.	12,860.	17,360.
Heat Cons. (LHV) X 10^6	Btu/h	1,742.5	1,402.9	1,118.8	755.2
Auxiliary Power	kW	1,390	1,390	1,390	1,390
Output Net	kW	172,510.	129,110.	85,610.	42,110.
Heat Rate (LHV) Net	Btu/kWh	10,100.	10,870.	13,070.	17,930.
Exhaust Flow X 10^3	lb/h	3552.	2871.	2389.	2162.
Exhaust Temp.	Deg F.	1113.	1149.	1193.	1032.
Exhaust Heat (LHV) X 10^6	Btu/h	970.1	823.5	721.0	550.1
Water Flow	lb/h	111,950.	80,050.	56,630.	25,120.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.
NOx AS NO2	lb/h	307.	245.	193.	129.
CO	ppmvd	20.	23.	34.	246.
CO	lb/h	62.	59.	71.	484.
UHC	ppmvw	7.	7.	7.	22.
UHC	lb/h	14.	11.	9.	26.
VOC	ppmvw	3.5	3.5	3.5	11.
VOC	lb/h	7.	5.5	4.5	13.
SO2	ppmvw	11.0	11.0	11.0	8.0
SO2	lb/h	90.0	72.0	58.0	39.0
SO3	ppmvw	1.0	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	8.0	6.0	4.0
Particulates	lb/h	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.86	0.89
Nitrogen	70.94	71.40	72.00	73.93
Oxygen	11.00	11.22	11.77	14.22
Carbon Dioxide	5.54	5.47	5.21	3.88
Water	11.68	11.06	10.17	7.08

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system. Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less. FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value. Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel. IPS- version code- 2 . 0 . 1 Opt: 9. 72410996 HENRYCO 01/28/2000 18:02 FPL Martin dis load rge 75

The Contractor will be allowed to apply offsets on exhaust flow, such that units with greater than guaranteed exhaust flow will offset units with less than guaranteed exhaust flow, in accordance with the following requirements. For a unit to be eligible for the application of offsets, its as-tested minimum exhaust flow shall be equal to or greater than 99 percent of the Exhaust Flow Guarantee. Thus, the maximum offset that can be applied to a unit is one (1) percent of the Exhaust Flow Guarantee. The Contractor will also not be allowed to increase the exhaust flow of a unit that has already tested and met the Exhaust Flow Guarantee in order to increase the level of its offset credit.

C.4 EXHAUST EMISSIONS GUARANTEES. The Contractor guarantees that the following emission values will not be exceeded during the emissions test or any other test conducted in association with measuring the performance of these units. The emission guarantees shall be met during all operation modes from the Minimum Acceptable Emissions Load (50 percent) to the full continuous (base) load capability of each unit for the specified fuels over the full range of specified site ambient conditions.

Emission Parameter	Guarantee Value Gas- Base	Guarantee Value Gas- Power Augmentation	Guarantee Value Distillate- Base
Carbon Monoxide, CO	9 ppmvd	15 ppmvd	20 ppmvd
Nitrogen Oxides, Nox	9 ppmvd @ 15% 0_2	12 ppmvd @ 15% 0_2	42 ppmvd @ 15% 0_2
Volatile Organic Compounds, VOC	1.4 ppmvd		3.5 ppmvd
Particulate (front half of CT only)	9 lb/hr		17 lb/hr
Particulate)front half plus back half of CT)	18 lb/hr		43 lb/hr
Opacity	5%		10%

Stack emissions tests shall be conducted on each combustion turbine unit following the completion of the final combustion turbine generator commissioning tests. The emissions tests may be conducted separately form or concurrently with the performance tests, a the discretion of the Purchaser. The emissions test will be conducted by an independent testing contractor with the assistance of the Contractor, in accordance with mutually agreed upon test procedures to be developed by the Purchaser and the Contractor. The Purchaser will witness the test and will furnish operators, startup power, and fuel. The Regulatory Authority, consisting of local, state, and/or federal agencies, may witness the tests.

The purpose of the emissions test is to demonstrate that the units meet the Contractor's emissions guarantees for all specified fuels. The emissions tests will also serve as compliance test to demonstrate that the units comply with all regulated emissions limits contained in the unit operating permit/air permit. The emissions tests shall be binding on the Contractor to determine compliance with guarantees.

Test instrumentation and methods shall be in accordance with the appropriate US EPA method for each specified pollutant. Measured data and calculated results will be deemed absolute

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 21-Mar-2000 07:43am
From: Alvaro Linero TAL
LINERO_A
Dept: Air Resources Management
Tel No: 850/921-9523

To: Rich_Piper (Rich_Piper@fpl.com)
CC: Jeff Koerner TAL (KOERNER_J)

Subject: Re: Response to Martin RAI

Rich. I would recommend having Bob call Jeff to make sure Bob understands each issues from Jeff's point of view. For example, the manner by which the 10.5 ppmvd is derived needs to be understood and discussed. We have received a number of virtually identical applications (dual fuel simple cycle 7FA units) from Golder with limits of 9 ppmvd with no "allowances" for degradation.

Jeff will get back to you directly. Al.

INTEROFFICE MEMORANDUM

Date: 21-Mar-2000 06:48am
From: Rich_Piper
Rich_Piper@fpl.com
Dept:
Tel No:

Subject: Response to Martin RAI

Al,

We should have a response to you and Jeff Koerner later this week. Please note that Ken Kosky is
on vacation, although we've been in touch via email. Due to Ken's absence, if it meets with your
approval, we'd like to go ahead and submit our response under Bob McCann's signature. Bob is
one of Ken's colleagues at Golder.

- Rich

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 10, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information
DEP File No. 0850001-001-AC (PSD-FL-286)
Two Simple Cycle, 170 MW Combustion Turbines in Martin County

Dear Mr. Lindsay:

On February 19, 2000, the Department received your application with sufficient fee for an air construction permit for two simple cycle, 170 MW combustion turbines to be located at FPL's Martin Plant. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The application identifies the General Electric Frame 7FA as the gas turbine model chosen for this project with DLN 2.6 combustors. Please provide <u>manufacturer</u> information supporting the proposed CO and NOx emissions standards of 10.5 ppmvd and 15 ppmvd, respectively. The Department is aware of other projects that plan to install this model turbine with standards of 9 ppmvd for both CO and NOx.

2. Please explain the statement on page 2-2 regarding, "*... degradation when the units operate over time and performance improvements beyond that provided by the manufacturer's guarantee. In particular, the combustion turbine emission estimates account for 5 percent higher power output and 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine.*"

   Recently, the Department attended a meeting in Cincinnati with General Electric, which included discussions with a representative of the Frame series gas turbine division. GE stated that the current guarantees for the Model 7FA were 9 ppmvd for both CO and NOx. In answer to several questions from the Department, GE could think of no technical reasons why the 7FA could not continue to meet these limits or why intermittent operation would adversely affect emission performance. Please provide supporting information that suggests higher emission rates are necessary, appropriate, or even recommended. The statement in the application seems to indicate that the "high power mode" of operation is outside of the manufacture's recommended performance of the unit and that FPL believes this operation will significantly degrade the units. Please comment.

3. When these units are converted to combined cycle operation as detailed in the "Ten Year Power Plant Site Plan, 1999 – 2008", what additional control equipment does FPL plan to install for the control of CO and NOx emissions? <u>Note</u>: *The temperature constraint imposed by simple cycle only*

operation would be relaxed making conventional SCR technically feasible. In addition, combined cycle operation is typically permitted for more than 8000 hours of operation per year, which would tend to make additional controls more cost effective. EPA and the Department have recently determined that conventional SCR systems are commercially available, have been demonstrated down to NOx emission levels of 3.5 ppmvd, and are cost effective.

4. According to the manufacturer, how many minutes of startup does it take the unit to reach 50% of base load? How many minutes does it take to shutdown the unit? Please estimate the number of startups in a year based on the proposed maximum 3390 hours per year of operation. The Department plans to address excess emissions from startup and shutdown in the BACT determination.

5. Please revise the SCR cost analysis based on the following:
   - Please explain the $50,000 cost for "additional NOx monitor and system"
   - Please explain the 6% tax. Is this Florida sales tax? Does this apply in all cases? Are deductions available for air pollution control equipment?
   - The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.
   - Please show the calculation for the estimated "tons" of ammonia needed.
   - The vendor quote is based on a turbine exhaust flow that includes the 11% "degradation". Doesn't this tend to inflate catalyst costs, ammonia costs, and the overall cost estimate?
   - On the first page of the Engelhard Corporation vendor quote, the system design basis indicates a similar quote for the Westinghouse Model 501D and the General Electric Model 7FA. It also suggests that the costs were based on an ammonia slip of 9 ppm for the 501D and 5 ppm for the 7FA. Please explain.

6. Please revise the oxidation catalyst cost analysis based on the following:
   - What additional "instrumentation" ($84,300) will be added as a result of the oxidation catalyst?
   - If necessary, revise this cost estimate with regard to the sales tax question in #5.
   - The cost estimate for "indirect costs" is based on "total capital costs". The OAQPS Cost Control Manual uses only the "direct capital costs" and does not include the "direct installation costs". Please correct.
   - The "heat rate penalty" includes a 0.2% MW output loss and a $3/mmBTU of additional fuel costs. Please explain why this wouldn't be considered "double-counting".

7. The Department received the modeling input/output files on March 3, 2000. Comments on the air quality impact analysis and additional impacts analysis will follow within thirty days of March 3.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Cleve Holladay, meteorologist, at 850/921-8986.

Sincerely,

A. A. Linero 3/10

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/jfk

Enclosure

cc: Mr. John M. Lindsay, FPL
Mr. Richard G. Piper, FPL
Ken Kosky, Golder Associates
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

cc: Buck Oven

Z 031 391 879

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to John Lindsay	
Street & Number FP & L	
Post Office, State, & ZIP Code Indiantown Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 0850001-001-AC PSD-FL-286 3-10-00	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
John Lindsay
FP & L - Martin Plant
PO Box 176
Indiantown, Fl
34956

4a. Article Number
Z 031 391 879

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
3/13/00

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Department of Environmental Protection

FLORIDA

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 23, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P.O. Box 25287
Denver, CO 80225

Re: FPL Martin Power Plant
Addition of Two New Combustion Turbines
Facility ID No. 0850001-008-AC, PSD-FL 286

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above referenced project. The applicant proposes to install two new General Electric Model 7FA combustion turbines. It is proposed to operate each unit in simple cycle mode for no more than 3390 hours per year. The primary fuel is natural gas with up to 500 hours of oil firing as a backup fuel. The application also requests power augmentation or a "high power mode" with slightly higher emissions.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/414-7268.

Sincerely,

2/23

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/jfk

Enclosures

Department of Environmental Protection

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Jeb Bush
Governor

David B. Struhs
Secretary

February 23, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, GA 30303

Re: FPL Martin Power Plant
Addition of Two New Combustion Turbines
Facility ID No. 0850001-008-AC - PSD-FL-286

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above referenced project. The applicant proposes to install two new General Electric Model 7FA combustion turbines. It is proposed to operate each unit in simple cycle mode for no more than 3390 hours per year. The primary fuel is natural gas with up to 500 hours of oil firing as a backup fuel. The application also requests power augmentation or a "high power mode" with slightly higher emissions.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/414-7268.

Sincerely,

A. A. Linero 2/23

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/jfk

Enclosures

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 22-Feb-2000 09:32pm
From: Alvaro Linero TAL
LINERO_A
Dept: Air Resources Management
Tel No: 850/921-9523

To: Jeff Koerner TAL (KOERNER_J)
CC: Kim Tober TAL (TOBER_K)

Subject: Re: FPL Martin Power Plant - New CTs

Jeff. It should have a brand new PSD number. It is a distinctly different project than whatever is already at Martin. Also log it into ARMS as an AC. I don't care what has been done in the past. See if we can show a correct fee of $0.00 by noting that a fee was paid to the Site Certification Office.

This project will not (repeat will not) go through Governor and Cabinet. Handle as closely as possible to a standard AC. Kim - please do it my way. Don't get any other advice. Just let me know if the system refuses to log the application for lack of a fee. Then we will go from there.

The benefits of being able to monitor the project by ARMS and having public access to the project status via the DEP website greatly outweighs the far-fetched possibility that we will develop a separate module for Site Certification.

Thanks. Al.