Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief, Bureau of Air Regulation by aa 3/5

THROUGH: Al Linero, Administrator - New Source Review Section aa 3/5

FROM: Greg DeAngelo

DATE: March 5, 2003

SUBJECT: Florida Power Hines Energy Complex
Project No. 1050234-006-AC
PSD Permit No. 330
Power Block 3; New 530 MW "2-on-1" Combined Cycle Gas Turbine

Attached for your review are the following items:

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

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, rule applicability, BACT determinations and permit conditions. The P.E. certification briefly summarizes the proposed project. The project is subject to power plant siting. Day No. 90 is May 19, 2003. I recommend your approval of the attached Draft Permit for this project.

AAL/gpd

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Florida Power Hines Energy Complex
Project No. 1050234-006-AC
Air Permit No. PSD-FL-330

PROJECT DESCRIPTION

The applicant proposes to construct a "2-on-1" nominal 530 megawatt (MW) combined cycle Power Block 3 consisting of two Siemens Westinghouse 501 FD gas turbine-electrical generator sets, an automated gas turbine control system, and an unfired heat recovery steam generator (HRSG). In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems. Each gas turbine will fire natural gas as the primary fuel and very low sulfur distillate oil as a restricted alternate fuel. (Restricted to the equivalent of 720 hours per year per unit.) Additional equipment includes two 125-foot combined cycle stacks.

CO, PM/PM_{10}, and VOC will be minimized by the efficient, high-temperature combustion of natural gas and distillate oil. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of very low sulfur distillate oil. NOx emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NOx controls, a selective catalytic reduction (SCR) system further reduces NOx emissions. These controls are determined to represent the Best Available Control Technology (BACT). No alternative method of operation is allowed; the units are only permitted for non-augmented, combined cycle operation. The draft permit includes the following standards for emissions of CO, NOx, VOC, and ammonia.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO	10	20	24 hour block
NOx	2.5	10	24 hour block
VOC	2	10	3 hours
Ammonia	5	5	3 hours

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

Gregory P. DeAngelo, P.E.
Registration Number: 58591

3/5/03
(Date)

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 5, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Bruce Baldwin, Vice President – Combustion Turbine Operations
Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Re: Project No. 1050234-006-AC (Air Permit No. PSD-FL-330)
Florida Power Hines Energy Complex
New 530 Megawatt Combined Cycle Power Block 3

Dear Mr. Baldwin:

Florida Power applied for a Prevention of Significant Deterioration (PSD) air permit to construct a new 530 megawatt "2-on-1" combined cycle gas turbine unit at the existing Florida Power Hines Energy Complex. The Florida Department of Environmental Protection ("the Department") has reviewed the application and additional information submitted and prepared the enclosed intent to issue permit package. The enclosures include the following: the "Intent to Issue Air Construction Permit," the "Public Notice of Intent to Issue Air Construction Permit," the "Technical Evaluation and Preliminary Determination" (draft Best Available Control Technology determinations), and the draft permit.

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

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Al Linero, Administrator of the New Source Review Section, at the above letterhead address. If you have any questions, please call Mr. Greg DeAngelo at (850)921-9506.

Sincerely,

AA Li

for Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/AAL/gpd

Enclosures

In the Matter of an
Application for Permit by:

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Authorized Representative:
Bruce Baldwin, Vice President – Combustion Turbine Operations

Project No. 1050234-006-AC
Draft Air Permit No. PSD-FL-330
Florida Power Hines Energy Complex
New Combined Cycle Power Block 3

INTENT TO ISSUE PSD PERMIT

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

The applicant, Florida Power, applied on September 4, 2002 to the Department for a PSD permit for a new 530 megawatt combined cycle gas turbine project (Power Block 3) at the existing Florida Power Hines Energy Complex, located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Polk County, Florida.

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

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

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue PSD Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Telephone (850)488-0114; Fax (850)922-6979. You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S., to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

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

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

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

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

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, F.S. 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), F.S., 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), F.S., 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, F.A.C.

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

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

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

for Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft Best Available Control Technology Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/5/03 to the persons listed:

Mr. Bruce Baldwin, Florida Power *
Mr. John J. Hunter, Florida Power
Mr. Ken Kosky, Golder Associates Inc.
Mr. Jerry Kissel, SWD
Mr. Gregg Worley, EPA Region 4
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.

Victoria Gibson (Clerk) March 5, 2003 (Date)

<u>**PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT**</u>

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. PSD-FL-330

Florida Power Hines Energy Complex, New Combined Cycle Power Block 3
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Florida Power. The permit is one of several authorizations needed to construct a nominal 530 megawatt (MW) combined cycle gas project at the Florida Power Hines Energy Complex, which is located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Polk County, Florida. In accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.), Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. Bruce Baldwin, Vice President – Combustion Turbine Operations. The applicant's address is Florida Power, P.O. Box 140442 – MAC BB1A, St. Petersburg, FL 33733-4042.

The applicant proposes to construct a "2-on-1" combined cycle Power Block 3 consisting of the following new equipment: two 170 MW gas turbine-electrical generator sets (CT 3A and CT 3B), two unfired heat recovery steam generators, and a common steam-electrical generator (190 MW). The gas turbines will be fired primarily with natural gas, with up to the equivalent of 720 hours per year per turbine of very low sulfur distillate oil allowed as a restricted alternate fuel. The gas turbines will only be operated in combined cycle mode. Additional equipment includes two 125-foot stacks.

During operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. When the turbines are firing natural gas, the permit will limit emissions of CO to 10 parts per million by volume on a dry basis (ppmvd) and emissions of NOx to 2.5 ppmvd, both as corrected to 15 percent oxygen The Department determines that these control techniques and equipment represent BACT in accordance with Rule 62-212.400, F.A.C. Emissions standards for oil firing, VOC emissions, and ammonia slip are presented in the draft permit on file with the Department.

Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines that comprise new Power Block 3 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	744	100	Yes
Lead (Pb)	0.02	0.6	No
NOx	267	40	Yes
PM/PM_{10}	121/121	15/25	Yes
SO_2	137	40	Yes
SAM	21	7	Yes
VOC	57	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels. Therefore, multi-source modeling was not required. The predicted impacts in the Chassahowitzka National Wilderness Area are less than the applicable PSD Class I significant impact levels; therefore, multi-source Class I PSD increment modeling was not required.

Notice for Newspaper

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 of the Florida Statutes (F.S.) before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S. 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, F.S. 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), F.S., 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), F.S., 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, F.A.C.

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A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

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

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

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8318
Telephone: (813)744-6100
Fax: (813)744-6084

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

Notice for Newspaper

TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

(Draft BACT Determinations)

PROJECT

Florida Power – Hines Energy Complex
Power Block 3 Combined Cycle Project

Project No. 1050234-006-AC
Draft Permit No. PSD-FL-330

COUNTY

Polk County

APPLICANT

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

PERMITTING AUTHORITY

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

March 5, 2003

Filename: 330 TEPD.doc

TABLE OF CONTENTS

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

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Facility Address

Florida Power – Hines Energy Complex
One Power Plaza (263 13th Ave S)
St. Petersburg, FL 33701

Authorized Representative:
Bruce Baldwin, Vice President – Combustion Turbine Operations

Processing Schedule

- Received application on September 4, 2002;
- Additional information requested on November 7, 2002;
- Received additional information on December 19, 2002 and February 19, 2003; application deemed complete.

Facility Description and Location

The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. The facility currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a 485 megawatt (MW) combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 heat recovery steam generators (HRSGs), and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit.

Power Block 3 ("the project") is a new "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 MW, and it will consist of two 170 MW gas turbine-electrical generator sets, two unfired HRSG sets, and a single 190 MW steam turbine-electrical generator. The plant will have a total generating capacity of approximately 1,545 MW following completion of Power Block 3. *{Note: Throughout this document, the electrical generating capacities represent nominal values for the given operating conditions.}*

Regulatory Categories

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case 112(g) determination of the Maximum Available Control Technology (MACT). This project may trigger a 112(j) case-by-case MACT determination pursuant to the "MACT hammer." (See Section 13, below.)

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act (CAA, or "the Act").

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

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

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

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a "2-on-1" combined cycle Power Block 3 consisting of the following equipment and specifications: two new 170 MW gas turbine-electrical generator sets (CT 3A and CT 3B), two unfired HRSGs, and a common 190 MW steam turbine-electrical generator.

Gas Turbine/HRSG Unit: Each gas turbine/HRSG unit consists of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests an aggregated fuel use limit of 27,365,000 gallons of oil per year for both turbines. This is equivalent to 1,000 hours per year per turbine for oil firing, assuming an ambient temperature of 59 °F and the corresponding maximum heat input rate of 1,932 MMBtu/hr.

Generating Capacity: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is 530 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas oxygen or carbon dioxide content.

Stack Parameters: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

Table 2-1. Combined Cycle Exhaust Characteristics

Fuel	Heat Input Rate (HHV)	Compressor Inlet Temp	Exhaust Temperature	Exit Velocity	Flow Rate
Gas	1,830 MMBtu/hour	59 °F	190 °F	59.2 ft/sec	1,009,487 acfm
Oil	1,932 MMBtu/hour	59 °F	270 °F	67.0 ft/sec	1,139,394 acfm

Potential Emissions

The project will result in emissions of CO, lead, NOx, PM/PM_{10}, SO_2, sulfuric acid mist (SAM), and VOC. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines).

Table 2-2. Applicant's Estimated Potential Emissions from the Project

Pollutant	Maximum Potential Emissions (tons per year)	PSD Significant Emission Rate (tons per year)	PSD Review Required?
CO	744	100	Yes
Lead	0.02	0.6	No
NOx	267	40	Yes
PM/PM_{10}	121/121	15/25	Yes
SO_2	137	40	Yes
SAM	21	7	Yes
VOC	57	40	Yes
Individual HAP (formaldehyde)	5.7	10 [a]	No
Total HAPs	7.3	25 [a]	No

[a] Criteria for case-by-case MACT determination pursuant to Section 112(g) of the Act.

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

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Florida Department of Environmental Protection (FDEP, or "the Department") to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following state rules and regulations of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, and adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Federal Regulations

This project is also subject to the applicable Federal provisions regarding air quality as established by the U.S. Environmental Protection Agency (EPA) in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 51	Submittal of Implementation Plans – PSD
Part 52	Approval of Implementation Plans – PSD

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

{Note: Acid rain requirements will be included in the Title V air operation permit. EPA proposed NESHAP for combustion turbines on January 14, 2003 (40 CFR Part 63, Subpart YYYY). See Sections 12 and 13, below, for a discussion of the applicability of 40 CFR Part 63.}

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's PSD program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the NAAQS for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

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

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Project emissions exceeding these rates are considered "significant." For each significant pollutant, the applicant must not only employ BACT to minimize emissions but also conduct an appropriate ambient impact analyses. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several significant regulated pollutants.

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

Description of PSD Preconstruction Review Requirements

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

- Any EPA determination of BACT pursuant to Section 169 of the Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.

- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

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

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

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

4. AVAILABLE INFORMATION

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

- U.S. Department of Energy (DOE) web site information on the Advanced Turbine Systems Project;
- Test data for various similar projects including Calpine facilities in Ontelaunee, Pennsylvania and Decatur, Alabama as well as the AEC facility in McWilliams, Alabama;
- EPA's Alternative Control Techniques Document, "NOx Emissions from Stationary Gas Turbines" (1993);
- DOE report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" (11/05/99), prepared by Onsite Sycom Energy Corporation;
- AP-42, Section 3.1 for gas turbines (04/00);
- EPA memorandums regarding gas turbines and MACT applicability dated 12/30/99 and 08/21/01; and
- Recently issued permits for the Siemens Westinghouse 501FD gas turbine.

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

5. DRAFT BACT STANDARDS – NITROGEN OXIDES

Discussion of NOx Emissions

A gas turbine is sometimes referred to a "heat engine." In operation, air is compressed, combusted with fuel to produce hot exhaust gases (≈ 2350 °F), and expanded in the turbine section to drive a shaft to produce useful energy. The majority of the energy produced is returned to the compressor and other supporting equipment. The remainder can be used to drive an electrical generator to produce electricity. This power cycle is known as the

Brayton cycle and is commonly referred to as the "simple cycle mode of operation." HRSGs may be added to convert the remaining heat energy of the exhaust gases into steam to drive a steam-electric turbine to produce additional electricity. This additional power cycle is known as the Rankine cycle. Gas turbines with HRSGs are commonly referred to as combined cycle units.

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

- *Thermal NOx* forms in the high temperature area of the gas turbine combustor. It increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen. Less NOx is formed during lean combustion (low fuel-to-air ratio) because the flame temperature is lower.
- *Prompt NOx* is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt NOx to overall NOx emissions is relatively small in combustors that operate near the stoichiometric air-to-fuel ratio. However, new combustors that operate in lean premix mode generate far less thermal NOx, which makes prompt NOx a greater contributor to overall NOx emissions for these types of units. Therefore, prompt NOx may provide a practical limit for NOx control by lean combustion.
- *Fuel NOx* forms from the oxidation of nitrogen in the fuel. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

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

Descriptions of Available NOx Controls

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

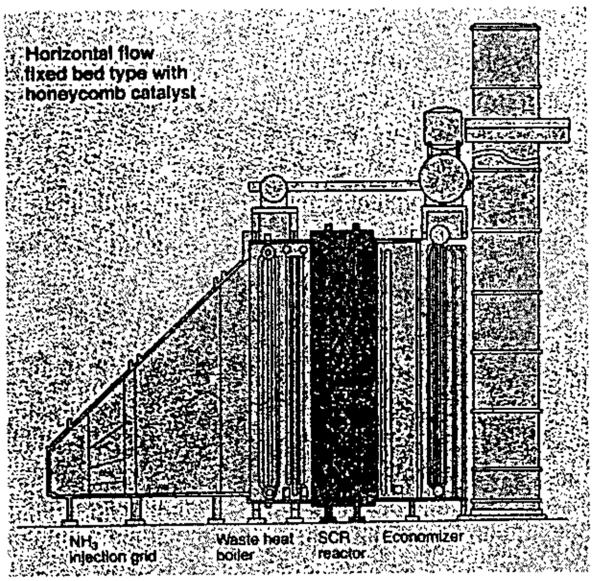
Lean Premix Combustor Design: Efforts over the last ten years to minimize NOx emissions from gas turbines have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. The Siemens Westinghouse DLN combustion technology is an example of a lean premix design. The following is a general description of the typical air/fuel combustion modes used to achieve lean premix combustion.

In the primary mode, fuel is supplied only to the primary (diffusion) nozzle to ignite, accelerate, and operate the unit over a range of low-load to mid-load operation and up to a given combustion reference temperature. Once the first combustion reference temperature is reached, operation in a lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in a secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone.

Finally, in the lean premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. In some models, such as the General Electric DLN-2.6 can-annular combustor, there is only flame present in the secondary stage even though premixed fuel and air are present in both the primary and secondary nozzles. The Siemens Westinghouse DLN combustors, by contrast, maintain a flame in the primary diffusion nozzle, which leads to slightly higher NOx emissions by comparison.

Lean premix combustion technology results in control efficiencies approaching 95%.

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

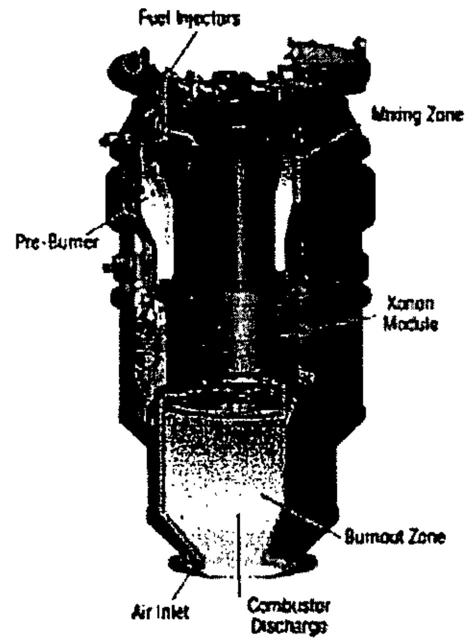


SCR: This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. The figure below shows the general arrangement of the ammonia injection grid and SCR catalyst with respect to the heat recovery steam generator for a combined cycle unit. The exhaust gas temperature must be maintained between 450 °F and 850 °F for this reaction to proceed satisfactorily. For combined cycle gas turbines, the temperature is within the proper range and conventional catalysts such as vanadium or titanium oxide are acceptable. Ammonia that escapes past the catalyst without reacting with NOx is called "ammonia slip." If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst. The catalyst is usually replaced every 5 to 7 years although vendors typically guarantee catalysts for about 3 years. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects permitted with very low NOx emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in control efficiencies approaching 98%.

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

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

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



Applicant's NOx BACT Proposal

Regarding selection of technology: In addition to the DLN combustion technology for the specified gas turbine, the applicant identified the following add-on control technologies for reducing NOx emissions: wet injection, SCR, SCONOx™, XONON™, NOxOUT™, Thermal DeNOx ™, and nonselective catalytic reduction (NSCR). Of these technologies, the applicant indicates that only DLN, wet injection, SCR, SCONOx™, and XONON™ are feasible for this project. The applicant does not believe that XONON™ nor SCONOx™ has been demonstrated for a "F-class" gas turbine. The applicant did review SCONOx™ as the top control technology, followed by SCR. These add-on controls would be in addition to DLN combustion for gas firing and wet injection for oil firing. The applicant noted the following adverse impacts with regard to SCONOx™.

- *Energy Impacts*: The pressure drop across the SCONOx™ system causes backpressure on the gas turbine, which can reduce power output. SCONOx™ also requires the use of natural gas and steam to regenerate the catalyst. The overall energy requirement is approximately equivalent to 35,600,000 kilowatt-hours (kWh) per year for each unit. The combined energy requirements in terms of natural gas usage would be 358 million cubic feet of natural gas per year, which is roughly 2.24% of the gas turbine heat input. The applicant believes that the energy impacts of SCONOx™ are approximately 6 times greater than those caused by SCR.
- *Environmental Impacts*: Because of the backpressure and energy requirements noted above, the applicant estimates that a SCONOx™ system would increase criteria pollutants for each gas turbine by 41 tons per year (and carbon dioxide emissions by 23,000 tons per year) over the levels attributable to a SCR system. The applicant does concede that ammonia is not used or emitted from the SCONOx™ system.
- *Economic Impacts*: The applicant estimates that the installation of SCONOx™ to achieve a NOx standard of 3.5 ppmvd corrected to 15% oxygen for gas firing would result in estimated annualized costs of about $5,674,000 per year and an overall cost effectiveness of $8,597 per ton of NOx removed. This compares to the applicant's estimated cost effectiveness of $2,741 per tons of NOx removed for an SCR system at 3.5 ppmvd corrected to 15% oxygen.

The applicant rejects SCONOx™ based on the significant energy, environmental, and economic impacts. SCONOx™ and SCR are capable of achieving nearly the same level of NOx reduction. Although SCONOx™ achieves this level without additional emissions of ammonia, SCR systems can be designed and operated to minimize ammonia slip. The use of distillate oil for this project further complicates the SCONOx™ system and can cause premature fouling through introduction of sulfur compounds. (It is possible that a SCOSOx™ catalyst could be added upstream to reduce SO_2 emissions.) The applicant believes that the energy and environmental disadvantages of a SCONOx™ system outweigh the any potential additional reductions in NOx. The applicant therefore requests a BACT determination of SCR with DLN for gas firing and wet injection for oil firing.

Regarding Selection of NOx Emission Rate: Following selection of SCR as the appropriate add-on control technology, the applicant addressed designing and operating the SCR to achieve 3.5 ppmvd versus 2.5 ppmvd, both corrected to 15% oxygen.

In addition to noting several issues in demonstrating compliance with an emission rate as low as 2.5 ppmvd corrected to 15% oxygen, the applicant presented energy, environmental, and economic impacts associated with the lower limit. The applicant estimates that achieving the lower emission rate of 2.5 ppmvd corrected to 15% oxygen would result in the following detrimental effects relative to achieving 3.5 ppmvd corrected to 15% oxygen:

- Backpressure increase of 4%;
- Energy loss of 206,222 kWh/year per turbine;
- 0.3 tons of additional criteria pollutants per year per turbine;
- 131 tons per year per turbine of additional carbon dioxide emissions; and
- $3,463 per ton of additional NOx removed (incremental cost effectiveness).

The applicant rejected the lower emission rate because of the increased difficulty in demonstrating compliance and the negative energy, environmental, and economic impacts. The applicant requests the following NOx standards as BACT.

a. Oil Firing 12 ppmvd corrected to 15% oxygen, 24-hour average

b. Gas Firing: 3.5 ppmvd corrected to 15% oxygen, 24-hour average

{Note: The requested gas firing limit represents approximately a 86% reduction from DLN combustion (25 ppmvd corrected to 15% oxygen).}

Department's Draft BACT Determination

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

- The pressure drop across the SCONOx™ system may be greater than that of SCR.
- The energy losses described for SCONOx™ relative to SCR are relatively small and would occur on a day-to-day basis. The additional negative impacts associated with SCR at 2.5 versus SCR at 3.5 ppmvd corrected to 15% oxygen are even smaller. The applicant's estimates of energy and environmental impacts assume that energy would be needed to replace the backpressure loss each and every day, 24 hours a day.
- The Department does not endorse the applicant's estimate of the cost effectiveness for either SCONOx™ or SCR. It is unlikely, however, that SCONOx™ would be cost effective for this project.
- The Department notes that the applicant presented a cost effectiveness value of $2,741 per ton of NOx removed for the 3.5 ppmvd corrected to 15% oxygen option, compared to just $2,770 per ton of NOx removed under the 2.5 ppmvd corrected to 15% oxygen option. The difference between the two estimated annual costs is less than 5 percent. Although the incremental cost is over $3,000 per ton, the lower NOx emission rate cannot be ruled out on grounds of cost effectiveness.

The Department rejects SCONOx™ primarily as not being cost effective and accepts conventional SCR as the BACT. The Department establishes the following draft BACT standards.

a. Oil Firing: 10 ppmvd corrected to 15% oxygen, 24-hour average

b. Gas Firing: 2.5 ppmvd corrected to 15% oxygen, 24-hour average

The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines. Oil firing will be subject to the same conditions as Power Block 2, namely an aggregated fuel consumption limit equivalent to 720 hours of operation for each unit. The oil firing limit is consistent with the determinations of the Department and other states.

Compliance with the standards will be demonstrated by CEMS. The Department set the averaging time for the NOx emission standard at a 24-hour block starting at midnight of each day. This averaging time simplifies compliance recordkeeping requirements, provides for sufficient averaging time to account for measurement uncertainties, and is appropriate given that the ambient NO_2 standard is based on an annual average.

These determinations are consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. In at least seven previous BACT determinations issued since August 2001, the Department specified a NOx BACT of 2.5 ppmvd corrected to 15% oxygen for "F-class" combined cycle gas turbines with conventional SCR. The Department also notes that other similar combined cycle projects in Maine and Washington received BACT limits of 2.0 ppmvd corrected to 15% oxygen for gas firing with SCR. The Department's proposed BACT limit considers measurement uncertainties associated with very low emission rates and the proposed ammonia slip limit of 5 ppmvd corrected to 15% oxygen. EPA Region 4 has commented that 2.5 ppmvd corrected to 15% oxygen represents the lowest BACT level in the region and that the 24-hour averaging period is acceptable in light of the low standard.

6. DRAFT BACT STANDARDS – CARBON MONOXIDE

Discussion of CO Emissions

Gas turbines emit CO because of incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. The DLN combustor design for modern "F-class" gas turbines, however, has successfully reduced CO emissions concurrently with lowered NOx emissions.

Applicant's CO BACT Proposal

The applicant identified two control options that are technically feasible and commercially available for gas turbines: (1) an efficient combustion design with good operating practices, and (2) a catalytic oxidation system designed to achieve a 2.5 ppmvd emission rate.

After attaining lean premix steady-state operation, the DLN combustion design proposed for this project results in low emissions of CO while also maintaining low NOx emissions. The automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters, such as the air/fuel distribution and staging, turbine speed, load conditions, temperatures, and heat input. No adverse energy, environmental, or economic impacts were identified with the use of an efficient combustion design and good operating practices. ("Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustor and control system.)

A catalytic oxidation system consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) at much lower temperatures (650 °F to 1150 °F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. Control efficiencies can approach more than 90% given a sufficient inlet concentration. The applicant identifies two alternatives for installing an oxidation catalyst. The first consists of an oxidation catalyst system prior to the HRSG to reduce CO emissions from the turbine. The second alternative is installing the catalyst system (or SCONOx™) within the HRSG. Capital costs and technical feasibility are not affected by placement relative to the HRSG.

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

Energy Impacts: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.5 to 2 inches of water gauge. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit resulting in an estimated energy penalty of approximately 3 million kWh/year. The applicant estimates the lost power generation to be approximately equivalent 32 million cubic feet of natural gas per year to replace the lost energy. Energy impacts are further exasperated when considering SCONOx^{TM}, which the applicant estimates would require the replacement of 35.8 MMBtu per year (358 million cubic feet of natural gas).

Environmental Impacts: The applicant contends that the maximum CO impacts are less than 0.1% of the applicable NAAQS and that no significant environmental benefit is realized by the installation of a catalytic oxidation system. The applicant states that making up the energy lost to the back pressure caused by an oxidation catalyst would result in 2,030 tons per year of additional carbon dioxide.

Economic Impacts: The applicant estimates that the installation of a catalytic oxidation system would result in total capital investment of approximately $1.64 million for one gas turbine with a total annualized cost of approximately $700,340 per year per gas turbine. Assuming 90% control efficiency, the catalytic oxidation system would remove in an additional 186 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $3,773 per ton of CO removed.

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

a. Oil Firing: 30 ppmvd corrected to 15% oxygen

b. Gas Firing: 16 ppmvd corrected to 15% oxygen

The applicant agreed that compliance is most appropriately determined by a CO CEMS on a 24-hour block average.

Department's Draft CO BACT Determinations

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

- The Department agrees that installation of a catalytic oxidation system would result in a small energy penalty due to the pressure drop across the catalyst.
- The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. The PSD preconstruction review process is specifically established for areas that are meeting the NAAQS in order to prevent the deterioration of the current air quality. Actual ambient impacts from the project are evaluated in the modeling analysis and are not considered in making the BACT determination.
- A catalytic oxidation system would also reduce emissions of VOC.
- The Department does not endorse the applicant's estimate of the cost effectiveness of $3,770 per ton of CO removed for a catalytic oxidation system. Recent similar projects (for example, CPV Gulfcoast) have obtained vendor equipment cost quotes that are approximately 25% less. However, the estimate appears to be within the high end of the range of such estimates for other similar projects ($1,500 to $4,500 per ton).

Recent tests for the same model gas turbine (Siemens Westinghouse 501FD) indicate actual CO emission levels significantly below the performance guaranteed by the manufacturer. Eight tests on 6 turbines operating at full load in Alabama and Pennsylvania show CO emissions averaging 1.1 ppmvd corrected to 15% oxygen. When operating at 85% load, average emissions in 2 tests were below 3 ppmvd corrected to 15% oxygen. Even at low load operation, available stack tests suggest that actual CO performance at levels below manufacturer guarantees is possible and attainable. The following tables summarize recent stack tests.

Table 6-1. Siemens Westinghouse 501FD Performance Test Summary (Base Load)

Plant	Unit	State	Test Date	Load	CO (ppmvd at 15% oxygen)			
					Run 1	Run 2	Run 3	Avg
Calpine - Decatur	1	AL	06/05/02	Base (100%)	0.35	0.34	0.17	0.29
Calpine - Decatur	2	AL	06/04/02	Base (100%)	0.26	0.43	0.43	0.37
Calpine - Decatur	1	AL	10/10/02	Base (100%)	1.73	1.07	1.87	1.56
Calpine - Decatur	2	AL	10/09/02	Base (100%)	1.31	1.37	1.48	1.39
AEC - McWilliams	1	AL	12/22/01	Base (100%)	2.06	2.31	2.47	2.28
AEC - McWilliams	2	AL	12/23/01	Base (100%)	2.47	1.99	1.95	2.14
Calpine - Ontelaunee	1	PA	08/13/02	Base (100%)	<0.41	<0.42	<0.42	<0.42
Calpine - Ontelaunee	2	PA	08/14/02	Base (100%)	<0.42	<0.42	<0.42	<0.42

Table 6-2. Siemens Westinghouse 501FD Performance Test Summary (Reduced Loads)

Plant	Unit	State	Test Date	Load	CO (ppmvd at 15% oxygen)			
					Run 1	Run 2	Run 3	Avg
AEC - McWilliams	1	AL	12/22/01	85%	2.75	2.86	2.74	2.78
AEC - McWilliams	2	AL	12/23/01	85%	2.26	2.48	2.67	2.47
AEC - McWilliams	1	AL	12/22/01	70%	16.81	17.08	17.33	17.1
AEC - McWilliams	2	AL	12/23/01	70%	12.59	12.73	13.45	12.9
Calpine - Decatur	1	AL	06/05/02	60%	1.27	0.81	0.54	0.87
Calpine - Decatur	2	AL	06/04/02	60%	13.04	8.04	6.55	9.21

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

Recognizing that the turbines will probably perform better than guaranteed by the manufacturer, the Department will require only that the HRSGs be designed to accommodate the future addition of an oxidation catalyst, should the turbine prove incapable of meeting the specified CO emission limit. If the turbine is not meeting the emission limit, then the addition of an oxidation catalyst would appear to be cost effective – especially since incorporating this possibility into the HRSG design should reduce the retrofit costs.

The Department establishes the following draft BACT standards.

a. Oil Firing: 20 ppmvd corrected to 15% oxygen, 24-hour block average

b. Gas Firing: 10 ppmvd corrected to 15% oxygen, 24-hour block average

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

7. DRAFT BACT STANDARDS – VOLATILE ORGANIC COMPOUNDS

Discussion

VOC emissions result from incomplete combustion when firing natural gas and distillate oil. Large combustion turbines offer high temperatures with efficient combustion resulting in relatively low levels of VOC. For this project, VOC emissions from one gas turbine are expected to be less than 30 tons per year. Similar to the control of CO, catalytic oxidation systems are available for reducing VOC emissions from gas turbines. Although one oxidation catalyst vendor noted that typical VOC removal in a turbine application is 30% to 40%, catalytic oxidation systems can achieve emissions reductions approaching 90% depending on the uncontrolled inlet VOC emission rate. The applicant suggested that even at 90% removal, such a system would not be cost effective for the control of CO emissions.

Applicant's Proposal

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

a. Oil Firing: 10 ppmvd corrected to 15% oxygen

b. Gas Firing: 2.0 ppmvd corrected to 15% oxygen

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

Department's Draft VOC BACT Determinations

Although the Department does not necessarily endorse the applicant's cost proposal, the Department nevertheless agrees that a catalytic oxidation system is not cost effective for this project. Therefore, the efficient combustion design and good operating practices are determined to represent BACT. The Department establishes the following draft BACT standards.

a. Oil Firing: 10 ppmvd as propane corrected to 15% oxygen

b. Gas Firing: 2.0 ppmvd as propane corrected to 15% oxygen

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

8. DRAFT BACT STANDARDS - PARTICULATE MATTER

Discussion – Gas Turbines

Emissions of particulate matter will result from incomplete combustion of natural gas and distillate oil as well as contaminants in these fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in a given fuel. However, natural gas is a clean fuel containing little ash, sulfur, or other contaminants. Similarly, distillate oil contains little of these contaminants and is restricted to the equivalent of only 720 hours per year per gas turbine for this project. (19,703,000 gallons aggregated among the 2 gas turbines, assuming 141.2 MMBtu per 1000 gallons and a firing rate of 1,932 MMBtu/hr.) Attachment A shows typical BACT determinations for particulate matter from large gas turbine projects. Some of the projects include front and back half catch for PM limits; therefore, comparison is not simple. Emissions of particulate matter when injecting ammonia for NOx control may be higher due to the formation of fine particulates such as ammonia sulfates and bisulfates.

Applicant's Proposal – Gas Turbines

At the estimated uncontrolled emission rates when firing natural gas, the applicant states the maximum particulate loading from the project will be less than normal fabric filter specifications. In addition to firing natural gas and very low sulfur distillate oil, the applicant proposes the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standard.

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

Department's Draft PM BACT Determinations – Gas Turbines

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

a. Visible emissions shall not exceed 10% opacity based on a 6-minute average.
b. The gas turbines shall fire natural gas as the primary fuel. The gas turbines may fire up to 19,703,000 gallons per year distillate oil containing no more than 0.05% sulfur by weight as a restricted alternate fuel.

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

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

Discussion

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

Applicant's Proposal

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

Department's Draft SAM/SO_2 BACT Determinations

The potential emissions from a single gas turbine are estimated to be 70 tons of SO_2 per year and 10.5 tons of SAM per year. Given the high flow rates and estimated low emission levels, the Department agrees that installation of add-on flue gas desulfurization equipment is not reasonable. All of the recent gas turbine projects control SO_2 and SAM by limiting the sulfur content of the fuel (See Attachment A). The projects ultimately rely on a fairly uniform gas distribution network, which typically provides natural gas with a fuel sulfur content of less than 1 grain per 100 standard cubic feet of gas. Distillate oil will be brought to the plant by truck and the vendor must meet contractual specifications regarding the fuel sulfur content. The Department determines that the following fuel specifications represent BACT for limiting emissions of SAM and SO_2 from the project.

a. The gas turbines shall fire natural gas as the primary fuel. The gas turbines may fire up to 19,703,000 gallons per year distillate oil containing no more than 0.05% sulfur by weight as a restricted alternate fuel.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. The above fuel specifications effectively limit potential emissions of SAM and SO_2 emissions, is typically considered BACT for similar gas turbine projects, and is clearly more stringent than the

NSPS Subpart GG standard of 0.8% sulfur by weight for gas turbines. Compliance with the fuel specifications shall be determined by records of the fuel analyses.

10. DRAFT STANDARDS FOR AMMONIA SLIP EMISSIONS

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

a. The SCR system shall be designed and operated for a maximum ammonia slip level of 5 ppmvd corrected to 15% oxygen.

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

11. NSPS REQUIREMENTS

Gas Turbines

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

- NOx (gas or oil) $\leq$ 112.5 ppmvd corrected to 15% oxygen (based on a heat rate of ~ 9.6 kilojoules per watt-hour or 9,100 Btu per kilowatt-hour); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. The applicant is referred to the latest version of the CFR for these requirements.

12. MACT 112(g) APPLICABILITY

EPA is required to promulgate MACT standards for HAP emissions from gas turbines. On January 14, 2003, EPA proposed the combustion turbines NESHAP (68 FR 1888). Because EPA has not yet promulgated these standards, states are required to review new projects for the applicability of Section 112(g) of the Act (see 40 CFR 63.40 - 63.44). If emissions from a new project are 10 tons per year or more of any single HAP or 25 tons per year or more of all combined HAPs, the new project could be subject to a case-by-case MACT determination. The applicant estimated total HAP emissions from the proposed project to be 7.3 tons per year, which would not trigger the 112(g) requirement.

In the memorandum dated August 21, 2001, EPA states that the original HAP emissions information (EPA memorandum dated 12/30/99) was based primarily on existing diffusion flame combustor technology. This technology results in higher emissions of CO, NOx, and HAPs than lean premix combustor designs, such as Siemens Westinghouse's DLN combustion technology. Based on additional emissions performance testing, EPA states that the average formaldehyde emission factor is 6.49 x 10^{-05} lb/MMBtu for large gas turbines (10 MW to 170 MW) utilizing lean premix combustion. Because formaldehyde had the highest emission rate for HAPs, it is reasonable to assume that other HAPs would also be much lower for lean premix combustion.

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

13. MACT 112(j) AND 40 CFR PART 63, SUBPART YYYY APPLICABILITY

Section 112(j) of the Act establishes the "MACT hammer" dates – deadlines for EPA to establish MACT standards through promulgation of NESHAP for the various source categories. In the event the applicable NESHAP is not yet finalized by its hammer date, Section 112(j) requires that the permitting authority perform a case-by-case MACT determination for all affected sources located at major sources of HAP emissions. The Section 112(j) rules are located at 40 CFR 63.50 through 63.56.

The combustion turbine NESHAP was only recently proposed (as 40 CFR 63, Subpart YYYY; see 68 FR 1888, January 14, 2003). The rule is scheduled to be promulgated – i.e., published as a final rule in the Federal Register – on August 30, 2003. If the NESHAP is not promulgated by October 30, 2003, then the Section 112(j) rules would require permit applications to initiate case-by-case MACT determinations for combustion turbines located at major sources of HAP emissions. (Note that this applicability analysis assumes EPA's proposed changes to the MACT hammer dates are adopted – see 67 FR 72875, December 9, 2002.)

Based on EPA guidance in the various preambles to the Section 112(j) rules, the applicability provisions in the proposed NESHAP should be used to make the decision regarding what constitutes an affected source for purposes of a case-by-case MACT determination. The proposed combustion turbines NESHAP lists the affected sources as "...any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions." (40 CFR 63.6090(a), proposed) Accordingly, the gas turbines at Power Block 3 would be affected sources – they are combustion turbines located at a major source of HAP emissions.

To comply with this requirement for Power Block 3, the permittee must submit the "Part 1 MACT application" within 30 days of startup. This Part 1 application simply notifies the permitting agency of the existence of the source and the applicability of the 112(j) standards. The Part 2 application, which contains the substantive information needed for the case-by-case MACT determination, can be submitted up to 24 months following the earlier Part 1 application.

Neither application need be submitted for Power Block 3, of course, if Subpart YYYY is promulgated prior to Power Block 3 startup. Subpart YYYY, if promulgated, will apply instead of the Section 112(j) rules. Instead of a case-by-case MACT, the source would comply with the general MACT for combustion turbines. Note that the Power Block 3 turbines will be considered "new stationary sources" for purposes of the MACT because their construction will commence after January 14, 2003. As such, Power Block 3 will have to comply with the emission limitations and operating limitations in Subpart YYYY upon startup.

In summary, if Subpart YYYY is promulgated prior to startup, then Power Block 3 must comply with Subpart YYYY at startup. If Subpart YYYY is not promulgated prior to startup, then the permittee must submit a Part 1 MACT application within 30 days of startup. If Subpart YYYY is still not promulgated 24 months after the Part 1 MACT application is submitted, then the Part 2 MACT application is due.

14. DEPARTMENT'S ESTIMATED ANNUAL EMISSIONS

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

Table 14-1. Estimated Annual Emissions

Pollutant	Project Emissions (tons per year)
CO	440
Lead	0.02
NOx	208
PM	107
SO_2	111
SAM	17
VOC	170

15. EXISTING AIR QUALITY IN THE VICINITY OF THE PROJECT

Description of Vicinity

The project will be located on County Road 555 in Bartow, Polk County. The site is several miles east of I-75 and south of I-4 in Polk County.

Refer to Figure 15-1. The immediate area is sparsely populated. St. Petersburg in Pinellas County is about 50 miles west of Hines across Tampa Bay. Tampa is about 35 miles northwest of the Hines Complex. TECO Polk is about 8 miles to the southwest of Hines and Lakeland Electric C.D. McIntosh is located about 20 miles to the north of Hines.

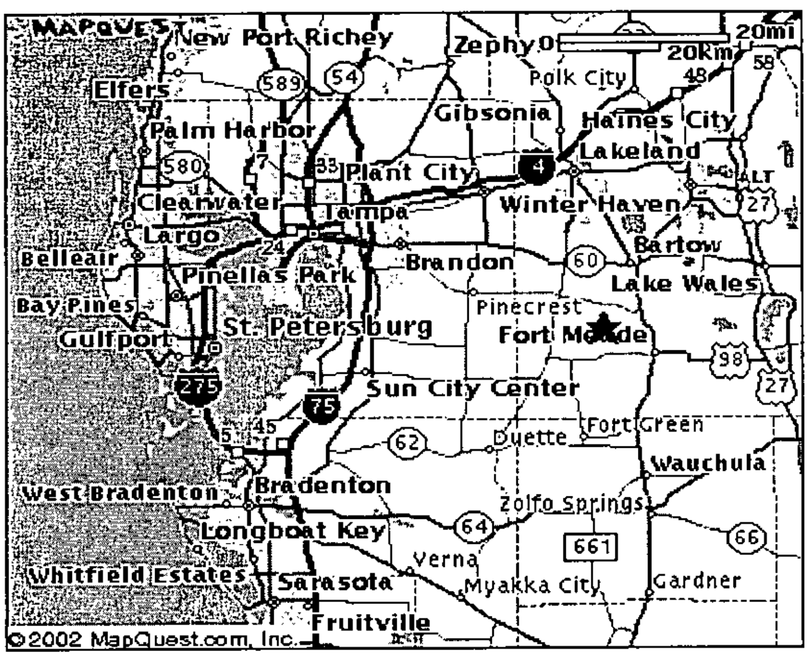


Figure 15-1. Location of Project, and Nearby Cities

Climate

The average January temperature for Polk County is 61.1 degrees F and the average August temperature is 81.8 degrees F. The average annual rainfall is 49.21 inches. Winds are predominately out of the East-Northeast.

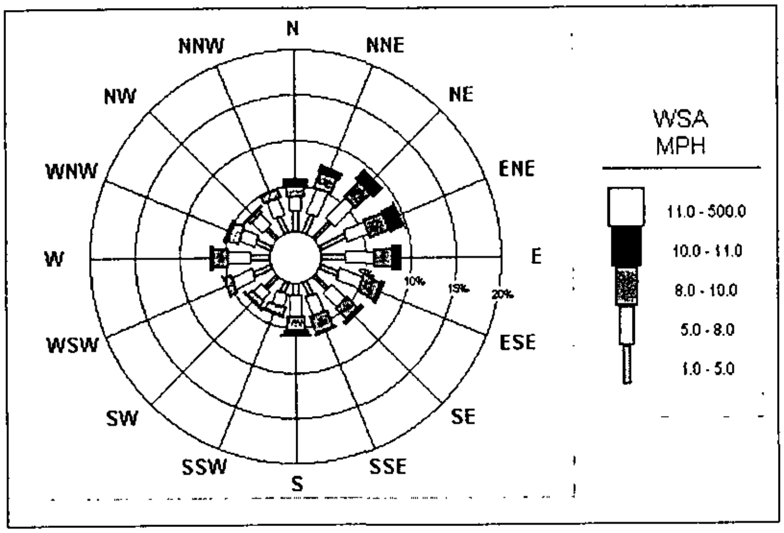


Figure 15-2. Polk County Wind Rose – January 2001 to December 2001

Major Stationary Sources in Polk County

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

Table 15-1. Major Sources of SO_2 in Polk County (2001)

Owner/Company	Site Name	Tons per year
Lakeland Electric	C.D. McIntosh Power Plant	10,409
IMC Phosphates Company	IMC Phosphates Co (New Wales)	9,395
Cargill Fertilizer, Inc.	Cargill Fertilizer - Bartow	4,262
Cargill Fertilizer, Inc.	Green Bay Plant	3,621
IMC Phosphates Company	IMC Phosphates Co (South Pierce)	3,467
U.S. Agri-Chemicals Corporation	U.S. Agri-Chemicals – Ft Meade	2,152
Tampa Electric	Polk Power Station	863
Lakeland Electric	Charles Larsen Memorial Power Plant	309
Florida Power	**Hines Power Block 3**	**137***

* Potential emissions based on application.

Table 15-2. Major Sources of NO_X in Polk County (2001)

Owner/Company	Site Name	Tons per year
Lakeland Electric	C.D. McIntosh Power Plant	7,951
Tampa Electric	Polk Power Station	616
IMC Phosphates Company	IMC Phosphates Co (New Wales)	404
Florida Power	Hines Energy Complex (existing facility)	327
Ridge Generating Station	Ridge Generating Station	304
Florida Power	**Hines Power Block 3**	**267***
Calpine	Auburndale Cogeneration Facility	215
Lakeland Electric	Charles Larsen Memorial Power Plant	206

* Potential emissions based on application.

Table 15-3. Major Sources of VOC in Polk County (2001)

Owner/Company	Site Name	Tons per year
Citrosuco North America	Citrosuco North America	1,047
Cargill Citro Pure, L.P.	Cargill Citro Pure, L.P.	788
Cutrale Citrus Juices USA, Inc.	Cutrale Citrus Juices	701
Citrus World, Inc.	Citrus World Inc.	353
Citrus World, Inc.	Florida's Natural Growers- Bartow	228
Carpenter Co., Insulation Division	Carpenter Co., Insulation Division	195
Southern Bakeries, Inc.	Butterkrust Bakeries	105
Lakeland Drum Service, Inc.	Lakeland Drum Service	82
Holly Hill Fruit Products	Holly Hill Fruit Products	73
Florida Power	**Hines Power Block 3**	**57***

* Potential emissions based on application.

Table 15-4. Major Sources of PM in Polk County (2001)

Owner/Company	Site Name	Tons per year
Lakeland Electric	C.D. McIntosh Power Plant	394
IMC Phosphates Company	IMC Phosphates Co (New Wales)	191
Florida Power	**Hines Power Block 3**	**121***
Cargill Fertilizer, Inc.	Green Bay Plant	120
IMC Phosphates Company	IMC Phosphates Co (South Pierce)	116
Cargill Fertilizer, Inc.	Cargill Fertilizer - Bartow	42

* Potential emissions based on application.

Table 15-5. Major Sources of CO in Polk County (2001)

Owner/Company	Site Name	Tons per year
Citrosuco North America	Citrosuco North America	928
Cutrale Citrus Juices USA, Inc.	Cutrale Citrus Juices	870
Florida Power	**Hines Power Block 3**	**744***
Ridge Generating Station	Ridge Generating Station	732
Lakeland Electric	C.D. McIntosh Power Plant	443
Cargill Citro Pure, L.P.	Cargill Citro Pure, L.P.	387
Citrus World, Inc.	Citrus World Inc.	282

* Potential emissions based on application.

Air Quality Monitoring in Polk County

Polk County has 7 monitors at 4 sites measuring PM, ozone, and SO_2. The 2001 Polk County monitoring network is shown in Figure 15-3.

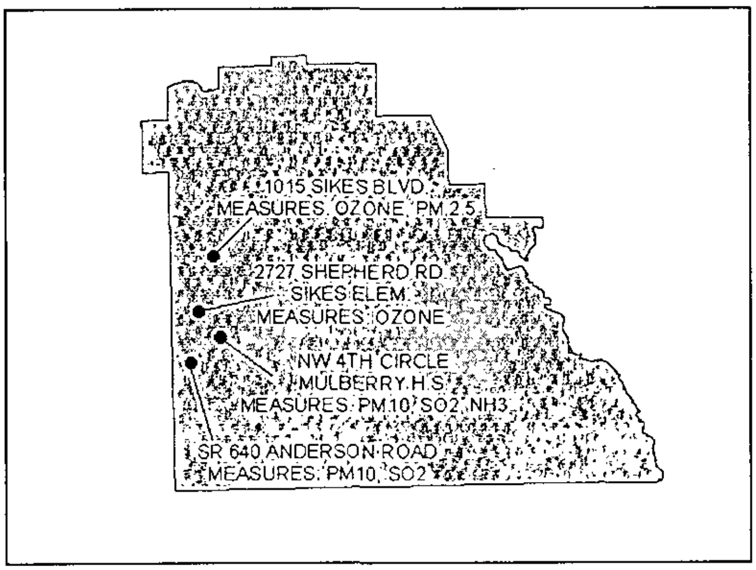


Figure 15-3. Polk County Monitoring Network

Ambient Air Quality in Polk County

Measured ambient air quality, along with the National Ambient Air Quality Standards, are given in the following table. Polk County is currently in attainment for all of the criteria pollutants.

Table 15-6. Existing Air Quality in Polk County

Pollutant	Site Location		Averaging Period	Ambient Concentration				
	City	Address		1st High	2nd High	Mean	Standard	Units
PM_{10}	Mulberry	Anderson and Pinecrest	24-hour	165	121		150[c]	ug/m^3
			Annual			25	50[b]	ug/m^3
	Mulberry	NW 4th Circle	24-hour	74	59		150[c]	ug/m^3
			Annual			23	50[b]	ug/m^3
SO_2	Mulberry	Anderson and Pinecrest	3-hour	59	48		500[a]	ppb
			24-hour	18	17		100[a]	ppb
			Annual			6	20[b]	ppb
	Mulberry	NW 4th Circle	3-hour	51	34		500[a]	ppb
			24-hour	14	11		100[a]	ppb
			Annual			4	20[b]	ppb
NO_2	Tampa	Simmons County Park	Annual			7	53[b]	ppb
CO	Plant City	One Raider Place	1-hour	5.2	2.8		35[a]	ppm
			8-hour	1.6	1.6		9[a]	ppm
Ozone	Lakeland	2727 Shepherd Rd	1-hour	0.111	0.109		0.12[c]	ppm
			8-hour					
	Lakeland	1015 Sikes Blvd	1-hour	0.113	0.106		0.12[c]	ppm
			8-hour					
$PM_{2.5}$	Polk	1015 Sikes Blvd	24-hour	59	35		65[c]	ug/m^3
			Annual			12	15[b]	ug/m^3

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

16. AIR QUALITY IMPACT ANALYSIS

Introduction

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

Significant Impact Analysis

For PM/PM_{10}, CO, NO_X and SO_2, which have significant impact levels defined for them, a significant impact analysis is performed. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described in Models and Meteorological Data Used in the Air Quality Analysis, later in this section. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas.

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

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels." These values are tabulated below and compared with the National Ambient Air Quality Standards.

Table 16-1. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual 24-Hour 3-Hour	0.04 4 17	1 5 25	60 260 1300	NO NO NO
PM_{10}	Annual 24-Hour	0.04 2.5	1 5	50 150	NO NO
CO	8-Hour 1-Hour	26 80	500 2000	10,000 40,000	NO NO
NO_2	Annual	0.09	1	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective ambient air quality standards. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA) located about 118 km to the north. The applicant's initial PM/PM_{10}, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels" for the Class I area. These values are tabulated below. Note that the values are miniscule if compared with the ambient air quality standards given in the previous table. Since these impacts are less than the respective significant impact levels, no further detailed modeling efforts are required in this Class I area.

Table 16-2. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project Compared with PSD Class I Significant Impact Levels (Chassahowitzka)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.001	0.2	NO
	24-hour	0.11	0.3	NO
NO_2	Annual	0.001	0.1	NO
SO_2	Annual	0.001	0.1	NO
	24-hour	0.15	0.2	NO
	3-hour	0.4	1	NO

Preconstruction Ambient Monitoring Requirements

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

Table 16-3. Maximum Project Air Quality Impacts for Comparison to the *de minimis* Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	2.5	10	~ 100	NO
NO_2	Annual	0.1	14	~ 15	NO
SO_2	24-hour	4	13	~ 40	NO
CO	8-hour	26	575	~ 2000	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC. However, the pollutant associated with VOC is actually ozone. Projects exhibiting VOC emissions greater than 100 tons per year (TPY) are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The proposed Power Block 3 project VOC emissions are predicted to be no more than 57 TPY, therefore an analysis, including ambient monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project is an analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area. The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Tampa International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1991 through 1995. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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

PSD Class I Area. The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I CNWA. Meteorological data used in this model was 1990 ISCST3 data, which was enhanced for CALPUFF. Meteorological surface data used were from Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers and Orlando. Meteorological upper air data used were from Ruskin, Apalachicola and West Palm Beach. Hourly precipitation data were obtained from 27 stations around the central part of the state.

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

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

<u>Additional Impacts Analysis</u>

Impact On Soils, Vegetation, And Wildlife. Very low emissions are expected from this natural gas-fired, with backup fuel oil, combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS).

The project impacts are also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the Hines Energy Complex Power Block 3. The combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

According to the application, native Floridian species of vegetation, such as cypress, slash pine, live oak, and mangrove, will not be visibly damaged when exposed to 1300 ug/m^3 of SO_2 for 8 hours. This proposed project is expected to emit 17 ug/m^3 of SO_2 over a 3-hour period and 4 ug/m^3 of SO_2 over a 24-hour period.

Impact On Visibility. Pipeline natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low NO_X, SO_2, and ammonia emissions will also minimize plume opacity and any effects on regional visibility.

The Class I Chassahowitzka NWA, where visibility impacts are normally of greater concern, is nearly 118 kilometers from the proposed site. Therefore impacts on visibility are expected to be insignificant.

Growth-Related Air Quality Impacts. According to the applicant, the project will require about 12 additional permanent employees, some of who will be drawn from the local labor force. Therefore, residential growth due to this project will be minimal.

The applicant also states that the existing transportation infrastructure is adequate for any additional vehicles that may be needed during construction of Power Block 3.

This project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint." After construction of the proposed project, Polk County is expected to remain below the National Ambient Air Quality Standards.

Hazardous Air Pollutants. The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any maximum achievable control technology (MACT) requirements pursuant to Department rules or Section 112 of the Clean Air Act.

Conclusion

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

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

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

17. DISCUSSION OF COMMERCIAL, RESIDENTIAL, AND INDUSTRIAL GROWTH SINCE 1977

The applicant submitted a report satisfying the requirements of Rule 62-212.400(3)(h)5., F.A.C., which states that a PSD application must include information relating to the air quality impacts of, and the nature and extent of, all general, residential, commercial, industrial, and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. The general conclusion of the growth report is that air quality has been meeting and will continue to meet the ambient standards even considering the impact of not only this project but also the growth that has occurred in Polk County since 1977.

Residential and Commercial Growth

Polk County population has increased 73 percent since 1977, with 204,000 more persons living in the county. There has been a corresponding increase of 68,000 households over the same time period, an increase of 58 percent.

Commercially, 524 establishments and 21,000 employees have been added to the retail sector, and another 413 businesses employing 4,600 persons have been introduced to the wholesale sector. The U.S. Department of Labor classifies Polk County as a "labor surplus area," meaning there are more unskilled laborers than jobs. The labor force as a whole has increased by 88,600 persons, or 85 percent, since 1977.

The tourism industry in Polk County has decreased somewhat, as evidenced by a 25 percent reduction in the number of hotels and motels in the county. At the same time, however, transportation rates have increased, most notably in the automotive sector. With the impact of three major interstates in the county, and given the county's proximity to many major metropolitan areas, there were 51 million more vehicle miles traveled in the county in 2001 compared to 1977 (a 62 percent increase).

Industrial Growth

The growth of the utility industry in Polk County has been considerable since 1977, when net electrical generation was around 400 MW. Currently, the county has nine power plants with a combined output of 2300 MW (an increase of 475 percent). An additional seven power plants are permitted or under construction, which will add another 2,200 MW to bring the total to 4,500 MW (an increase of over 1000 percent). Note that the 4,500 MW total does not include this current project.

The citrus industry in Polk County peaked in the late 1980s and early 1990s, but has seen a net decrease in production since 1977 (by approximately 22 percent). Phosphate mining has also decreased considerably since 1977, falling some 36 percent. Manufacturing has increased slightly, by around 5 percent.

Air Quality Impacts and Trends

Emissions of air pollutants from mobile sources has seen significant decreases since 1977. CO has fallen by 80 percent, VOC has decreased 80 percent, and NO emissions are 56 percent lower.

Ambient monitoring data detail SO_2 and PM_{10} or total suspended particulate (TSP) concentrations since 1977. Ozone concentrations have been monitored since 1992. SO_2 concentrations have historically been well below the NAAQS. TSP, when it was monitored (1977 - 1987), occasionally exceeded the ambient standards, but since the standard was revised to monitor PM_{10} in 1988, the air quality has been below the NAAQS. Ozone has been below both the 1-hour and the 8-hour ambient standards since it has been monitored.

Conclusions

- Growth since 1977 has not adversely impacted the attainment of the NAAQS for SO_2, PM_{10}, or ozone.
- The increase in vehicle miles traveled in the county has been offset by decreases in pollution per vehicle, yielding a significant net decrease in emissions from mobile sources.
- The mining and citrus industries have slowed down considerably from 1977 levels.
- Manufacturing and commercial growth has increased along with population growth.
- Growth in the electric utility industry has far exceeded the corresponding growth in the residential, commercial, and other industrial sectors of Polk County.

18. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and Federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft BACT determinations, review of the air quality impact analysis, and the conditions specified in the draft permit. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. Greg DeAngelo is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at (850)921-9506 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

ATTACHMENT A

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

Project Location	Capacity (MW)	NOx Limit – Fuel Type (ppmvd @ 15% O_2)	Technology	Comments
FPC Hines III, FL	**530**	**2.5 – NG** **10 – FO**	**SCR** **WI**	**2x170 MW WH501F (Draft)** **Equivalent of 720 hours oil / turbine**
FPL Martin, FL	1150	2.5 – NG 10.0 – FO	SCR WI	4x170 MW GE 7FA CT (Draft)
El Paso Manatee, FL	250	2.5 – NG	SCR	175 MW GE 7FA
El Paso Deerfield, FL	250	2.5 – NG	SCR	175 MW GE 7FA (Draft 8/2001)
CPV Pierce, FL	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT (7/2001)
Metcalf Energy, CA	600	2.5 – NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce, FL	~250	3.5 – NG 10 - FO	SCR	170 MW MHI501F CT Repowering
CPV Atlantic, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
CPV Gulfcoast, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
TECO Bayside, FL	1750	3.5 – NG 12 - FO	SCR	7x170 MW GE 7FA CTs, Repowering
FPC Hines II, FL	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F Equivalent of 720 hours oil / turbine
Calpine Osprey, FL	527	3.5 – NG	SCR	2x170 MW WH501F Draft 5/00
Calpine Blue Heron, FL	1080	3.5 – NG	SCR	4x170 MW WH501F Draft 2/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG 15 - FO	SCR	170 MW GE 7FA. 11/99

Notes:

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

Table A-2. Other Recent Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast

Project Location	CO - ppmvd (or lb/MMBtu)	VOC - ppmv (or lb/MMBtu)	PM - lb/MMBtu (or gr/dscf or lb/hr)	Technology and Comments
FPC Hines III, FL	**10 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)**	**2 – NG 10 – FO**	**10% Opacity – NG 5 ammonia – NG/FO**	**Clean Fuels Good Combustion**
FPL Martin, FL	10.0 – NG 15.0 – FO	1.3 – NG 2.5 – FO	10% Opacity	Clean Fuels Good Combustion
El Paso Manatee, FL	9 (7.4 @15% O_2) 15 (12 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Deerfield, FL	9 (7.4 @15% O2) 15 (12 @15% O2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Pierce, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/MMBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Enron Ft. Pierce, FL	3.5 - NG 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity	Oxidation Catalyst Clean Fuels Good Combustion
CPV Atlantic, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Gulfcoast, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	9 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)	1.3 – NG 3 - FO	12 lb/hr – NG 30 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	16 - NG (24-hr CEMS) 30 – FO (24-hr CEMS)	2 – NG 10 – FO	10% Opacity – NG 5/9 ammonia – NG/FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Calpine Blue Heron, FL	10 – NG (24-hr CEMS) 17 – NG (DB&PA)	1.2 – NG 6.6 – NG (DB&PA)	31.9 lb/hr – NG (DB&PA) 10 percent Opacity 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry, AL	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/MMBtu – (CT) 0.011 lb/MMBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
KUA Cane Island, FL	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion

Notes:

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

DRAFT PERMIT

PERMITTEE:

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Authorized Representative:
Bruce Baldwin, Vice President – Combustion Turbine Operations

Hines Energy Complex, Power Block 3 Project No. 1050234-006-AC Air Permit No. PSD-FL-330 SIC No. 4911
Expires: June 30, 2007

PROJECT AND LOCATION

This permit authorizes the construction of Power Block 3 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The project was processed in accordance with Florida's program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a 485 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 3), the plant will have a total generating capacity of approximately 1,545 MW.

NEW AND MODIFIED EMISSIONS UNITS

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

ID	Emission Unit Description
016	Power Block 3, CT 3A (170 MW gas turbine with unfired HRSG)
017	Power Block 3, CT 3B (170 MW gas turbine with unfired HRSG)

{Permitting Note: Florida Power Hines Energy Complex Power Block 3 (Power Block 3, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 3A and CT 3B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). This project may trigger a case-by-case MACT determination pursuant to Section 112(j) of the Act – the "MACT hammer." (See Appendix YY.)

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

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

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

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

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix AL	Acronym List
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix CF	Citation Format and Definitions
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix SC	Standard Conditions
Appendix XS	Semiannual NSPS Excess Emissions Report
Appendix YYYY	NESHAP Subpart YYYY and 112(j) MACT Hammer

REVIEWING AND PROCESSING SCHEDULE

September 4, 2002	Received permit application and fee
November 7, 2002	Department's request for additional information (via Office of Siting Coordination's sufficiency questions)
December 19, 2002	Received response to sufficiency questions
February 19, 2003	Received report documenting commercial, residential, and industrial growth since August 7, 1977
February 19, 2003	Application complete
^ DRAFT	Distributed Notice of Intent to Issue and supporting documents
^ DRAFT	Notice of Intent to Issue published in ^ DRAFT

RELEVANT DOCUMENTS

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

- Permit application
- Department's request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant's additional information
- Department's Technical Evaluation and Best Available Control Technology (BACT) Determination
- Department's Intent to Issue

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

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

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

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

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

POWER BLOCK 3 COMBINED CYCLE GAS TURBINES (EUs 016 AND 017)

This section of the permit addresses the following emissions units.

Emission Units 016 and 017

Description: Emission units 016 and 017 each consist of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

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

Generating Capacity: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Stack Parameters: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

Fuel	Heat Input Rate (HHV)	Compressor Inlet Temp	Exhaust Temperature	Exit Velocity	Flow Rate
Gas	1,830 MMBtu/hour	59 °F	190 °F	59.2 ft/sec	1,009,487 acfm
Oil	1,932 MMBtu/hour	59 °F	270 °F	67.0 ft/sec	1,139,394 acfm

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, PM/PM_{10}, sulfuric acid mist (SAM), SO_2, and VOC. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. New Source Performance Standards (NSPS): The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two Siemens Westinghouse Model 501 FD gas turbine-electrical generator sets each with a generating capacity of

170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]

4. Gas Turbine NOx Controls

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

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

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

5. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 3A or CT 3B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]

6. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 3.5 ppmvd corrected to 15% oxygen.

PERFORMANCE RESTRICTIONS

7. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

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

   a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

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

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	10	20	24 hour block
NOx [b]	2.5	10	24 hour block
VOC [c]	2	10	3 hours
Ammonia [d]	5	5	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

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

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

e. The fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section.

{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *PM_{10} = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *SO_2 = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO_2 emissions.} [Rule 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

10. Operating Procedures: The BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

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

13. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of startup, shutdown, oil-to-gas fuel switches, and documented malfunctions may be excluded from the

block average calculated to demonstrate compliance with the emission limits of Condition No. 9 of this section.

a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold startups. A "cold startup" is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period.

b. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block.

c. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

d. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

e. All periods of data excluded for any startup, shutdown, oil-to-gas fuel switches, or documented malfunction shall be consecutive for each episode. Periods of data excluded for all startup, shutdown, oil-to-gas fuel switches, or documented malfunctions shall not exceed four hours in any 24-hour block.

f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

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

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

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.

Method	Description of Method and Comments
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

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

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

17. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of PM/PM10 and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

    a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*

    b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

    {Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.} [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

19. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

20. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall not be greater than 50 ppm, as corrected to 15% oxygen.

    b. *NOx Monitors.* The NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% oxygen.

    c. *Diluent Monitors.* The oxygen or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO_2 on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NOx emissions depending on the use of alternate fuels}.* [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 13 and 14 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

h. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

21. <u>Water Injection Monitoring Requirements</u>: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and

record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

22. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

23. Monitoring of Operation: To demonstrate compliance with the fuel consumption and sulfur content limits of Condition No. 8 of this section, the permittee shall monitor and record the rates of consumption and sulfur content of each of the allowable fuels in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

24. Frequency of Recordkeeping: Condition No. 20 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]

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

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

26. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Conditions Nos. 13 or 14 of this section, the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the

probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]

27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

28. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 13 and 14 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800; 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

CONTENTS

ACRONYM LIST

acfm	Actual cubic feet per minute
ASTM	ASTM International [1]
BACT	Best Available Control Technology
Btu	British thermal unit
CAA, or "the ACT"	Clean Air Act, as amended in 1990
CEMS	Continuous emission monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
CO_2	Carbon dioxide
DLN	Dry-low NOx
EPA	U.S. Environmental Protection Agency
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FDEP, or "the Department"	Florida Department of Environmental Protection
HAP	Hazardous air pollutant
HHV	Higher heating value
HRSG	Heat recovery steam generator
LAER	Lowest Achievable Emission Rate
LHV	Lower heating value
MMBtu	Million British thermal units
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOx	Nitrogen oxides
NSPS	New Source Performance Standards
PM/PM_{10}	Particulate matter
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RATA	Relative accuracy test assessment
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
VOC	Volatile organic compound

[1] Formerly known as American Society for Testing and Materials.

OVERVIEW

The project added a 530 megawatt (MW) "2-on-1" combined cycle gas turbine system to the existing Florida Power Hines Energy Complex. Significant emissions increases pursuant to the Prevention of Significant Deterioration (PSD) rule required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

BACT CONTROL TECHNOLOGIES

The Florida Department of Environmental Protection (the "Department") reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" as revised prior to the siting hearing. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

BACT for CO Emissions

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

Catalytic Oxidation: At the anticipated CO emissions rate, the Department does not consider the addition of a catalytic oxidation system for control of CO to be cost-effective. Catalytic oxidation – while not BACT – must be considered in the design of the heat recovery steam generators. The design must be such that the oxidation catalyst system can be readily installed in the future. If the as-built combined cycle unit cannot achieve the BACT CO emission limit, however, then the cost-effectiveness of the catalytic oxidation system improves and the Department shall require it to be installed.

BACT for NOx Emissions

Dry Low-NOx (DLN) Combustion: When firing natural gas, BACT for NOx emissions is the operation of Siemens Westinghouse's DLN combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in low NOx emissions. The control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

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

Selective Catalytic Reduction (SCR): When firing natural gas or distillate oil, BACT for NOx emissions is the operation of the SCR system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the heat recovery steam generator, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. The SCR system will achieve about a 70% reduction with an initial ammonia slip of no more than 5 ppmvd.

BACT for VOC Emissions

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

BACT for PM, SAM, and SO2 Emissions

Fuel Specifications: BACT for PM, SAM, and SO2 emissions is the use of natural gas as the primary fuel (≤ 1.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil (≤ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

BACT STANDARDS

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

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	10	20	24 hour block
NOx [b]	2.5	10	24 hour block
VOC [c]	2	10	3 hours
Ammonia [d]	5	5	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

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

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of Section III of this permit, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

e. The fuel specifications established in Condition No. 8 of Section III of this permit – combined with the efficient combustion design and operation of each gas turbine – represents the BACT determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in Condition No. 8 of Section III of this permit effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of Section III of this permit.

{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *PM_{10} = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *SO_2 = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO_2 emissions.}

If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall: begin testing and reporting the ammonia slip for each subsequent calendar quarter; before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions. Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

FINAL BACT DETERMINATIONS

As summarized above, the Department determines that the standards specified in this permit represent BACT for emissions of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

Determination By:

^ DRAFT

Gregory P. DeAngelo, P.E., Project Engineer
New Source Review Section

Recommended By:

^ DRAFT

Trina Vielhauer, Chief
Bureau of Air Regulation

Approved By:

^ DRAFT

Howard L. Rhodes, Director
Division of Air Resources Management

CITATION FORMAT AND DEFINITIONS

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

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

PSD Permit Numbers

Example: Permit No. PSD-FL-330

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

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7 of the Code of Federal Regulations

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

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

(179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

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

(275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);

    b. Determination of Prevention of Significant Deterioration (X); and

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

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;

        2) The person responsible for performing the sampling or measurements;

        3) The dates analyses were performed;

        4) The person responsible for performing the analyses;

        5) The analytical techniques or methods used; and

        6) The results of such analyses.

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

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

The Power Block 3 gas turbines are regulated as emissions units 016 and 017. Each Power Block 3 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG. [40 CFR 60.330(a) and (b), Applicability and Designation of Affected Facility.]

Emissions units subject to a NSPS are also subject to the applicable requirements of 40 CFR Part 60, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

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

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

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as defined in § 60.332(a)(3).

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

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

where:

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

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

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 9.6 for both natural gas and fuel oil. The equivalent emission standards are 112.5 ppmvd at 15% oxygen. The BACT limits of this permit are more stringent than this requirement.]

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

§ 60.333 Standard for Sulfur Dioxide.

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

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

[Note: The BACT limits of this permit are more stringent than this requirement.]

§ 60.334 Monitoring of Operations.

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

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

<u>Department requirement</u>: **The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.**

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

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

Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator is allowed to determine the sulfur content of the pipeline quality natural gas semi-annually, because the owner or operator has the results of bimonthly and quarterly natural gas sulfur content analyses from the operation of the existing Power Block 1.

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

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

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

Department requirement: NOx emission monitoring by CEMS shall substitute for the requirements of paragraph (c)(1) because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 as described in Condition No. 27 of Section III of this permit.

Department requirement: NOx and CO monitor availability shall not be less than 95% in any calendar quarter. The report required by Condition No. 28 of Section III of this permit shall be used to demonstrate compliance with this requirement.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

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

§ 60.335 Test Methods and Procedures.

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

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

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

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

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

where:

NOx = emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

Po = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

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

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

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

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

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

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

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance be based on a

minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in Condition No. 20 of Section III of this permit shall be used instead of the span value of 300 ppm specified by paragraph (3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

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

Department requirement: Condition No. 25 of Section III of this permit requires the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

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

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

[Note: The fuel analysis requirements of Condition No. 25 of Section III of this permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

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

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

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

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

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

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

14. Determination of Process Variables

    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

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

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

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

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

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

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

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

Reporting period dates: From ______________________ to ______________________

Company: ______________________

Emission Limitation: ______________________

Address: ______________________

Monitor Manufacturer: ______________________

Model No. : ______________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ______________________

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

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

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

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

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

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

Name: ______________________

Signature: ______________________ *Date*: ______________________

Title: ______________________

NESHAP SUBPART YYYY AND 112(J) MACT HAMMER

APPLICABILITY

The Power Block 3 gas turbines are regulated as emissions units 016 and 017. Each Power Block 3 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new source requirements of the combustion turbines NESHAP, 40 CFR 63, Subpart YYYY, when that subpart is finalized.

Emissions units subject to a NESHAP are also subject to the applicable requirements of 40 CFR Part 63, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

TIMING AND REQUIREMENTS

The combustion turbines NESHAP was proposed on January 14, 2003. It is currently scheduled for promulgation by August 30, 2003. If the combustion turbines NESHAP is promulgated prior to startup of the Power Block 3 combustion turbines, then:

- The permittee shall apply for a permit revision to this permit to incorporate the relevant requirements of 40 CFR 63, Subparts A and YYYY, and ensure compliance with those standards prior to startup of the Power Block 3 combustion turbines.

If, however, the combustion turbines NESHAP is not promulgated prior to startup of the Power Block 3 combustion turbines, then:

- Within 30 days of startup of the Power Block 3 combustion turbines, the permittee shall submit a "Part 1 MACT application" as specified in the Section 112(j) rules, currently located at 40 CFR 63.53(a).
- If 40 CFR 63, Subpart YYYY, is promulgated within 24 months of submitting the Part 1 MACT application, then the permittee shall apply for a permit revision to this permit to incorporate the relevant requirements of 40 CFR 63, Subpart YYYY, and ensure compliance with those standards prior to the date 24 months following submittal of the Part 1 MACT application.
- If 40 CFR 63, Subpart YYYY, is not promulgated within 24 months of submitting the Part 1 MACT application, then the permittee shall submit a "Part 2 MACT application" as specified in the Section 112(j) rules, currently located at 40 CFR 63.53(b). The Part 2 MACT application shall be submitted prior to the date 24 months following submittal of the Part 1 MACT application.

[Rule 62-4.070(3), F.A.C. See also 40 CFR 60.6085, proposed at 68 FR 1888, January 14, 2003.]

SENDER: *COMPLETE THIS SECTION*

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1. Article Addressed to:

Mr. Bruce Baldwin
Vice President, Combustion Turbine Operations
Florida Power
P. O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

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City, State, ZIP+4: St. Petersburg, FL 33733-4042

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