Memorandum

Florida Department of Environmental Protection

TO: C. H. Fancy

THRU: Scott M. Sheplak SMS

FROM: Edward Svec

DATE: September 10, 2001

SUBJECT: South Pond Energy Park
DEP File No. 0490046-001-AC (PSD-FL-306)

Attached is the draft public notice package including the Intent to Issue and the Technical Evaluation and Preliminary Determination for the construction of a nominal 600 MW gas turbine power plant south of Ft. Green in Hardee County. The facility will consist of two GE Frame 7FA natural gas fired turbines operated in the simple cycle mode and restricted in hours of operation. A third turbine will operate in the combined cycle mode and will not be restricted in operating hours. However, the permittee is restricting the output of the unfired HRSG to 74.9 MW to avoid Power Plant Citing. A determination of BACT was required. The project meets all ambient air quality standards.

I recommend your signature and approval of the cover letter and Intent to Issue, with the exception of limiting the use of fuel oil for simple cycle operation. Fuel oil use was restricted to 500 hours contrary to the applicant's request and the opinion of the review engineer.

SMS/es

Attachments

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:
South Pond Energy Park, LLC
600 MW Electrical Power Plant

Permit No.: 0490046-001-AC, PSD-FL-306
Facility ID No.: 0490046

Project type: Air Construction Permit

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

Scott M. Sheplak — 10/10/01
Scott M. Sheplak, P.E. — date
Registration Number: 48866

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/921-9532
Fax: 850/922-6979

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 12, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Richard L. Wolfinger, Vice President
South Pond Energy Park, LLC
111 Market Place, Suite 200
Baltimore Maryland 21202

Re: DEP File No. 0490046-001-AC (PSD-FL-306)
South Pond Energy Park
600-Megawatt Power Plant

Dear Mr. Wolfinger:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the South Pond Energy Park to be located near Ft. Green, Hardee County. The Department's Intent to Issue Air Construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

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

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Scott M. Sheplak, P.E. Administrator, Title V Section at the above letterhead address. If you have any questions please call Mr. Edward Svec at 850/921-8985.

Sincerely,

CH Fancy

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

CHF/es

In the Matter of an
Application for Permit by:

Mr. Richard L. Wolfinger, Vice President
South Pond Energy Park, LLC
111 Market Place, Suite 200
Baltimore, Maryland 21202

DEP File No. 0490046-001-AC (PSD-306)
South Pond Energy Park
Hardee County

________________________________/

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

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

The applicant, South Pond Energy Park, LLC, applied on November 17, 2000 to the Department for an air construction permit to construct a nominal 600-megawatt natural gas-fueled combustion turbine power plant for the South Pond Energy Park to be located south of Ft. Green, Hardee County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), 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 an air construction permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

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, and 62-297, F.A.C.

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

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

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. The Department will also accept written and oral comments at a public hearing (meeting) to be held as described in 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.

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/12/01 to the person(s) listed:

Mr. Richard L. Wolfinger, South Pond Energy Park, LLC*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, PE, DEP SWD
Kennard Kosky, PE Golder Associates

10/12/01 cc: Ed Svec
Reading File

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.

Barbara J. Friday 10/12/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0490046-001-AC (PSD-FL-306)

South Pond Energy Park
Hardee County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to South Pond Energy Park. The permit is to construct a nominal 600-megawatt (MW) natural gas-fueled power plant two miles south of Ft. Green on Ft. Green Road, Hardee County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), volatile organic compounds (VOC), sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are South Pond Energy Park, LLC, 111 Market Place, Suite 200, Baltimore, Maryland 20.

South Pond Energy Park proposes to construct three nominal 174-MW General Electric Frame 7FA natural gas-fired combustion turbine-electrical generators. Two of the units will operate in simple cycle mode and intermittent duty. The other unit will operate in combined cycle mode and will include an unfired heat recovery steam generator and a separate steam-electrical generator.

Additional equipment includes an 84 million Btu auxiliary boiler, a 2.8 million gallon fuel oil storage tank, an emergency diesel powered fire pump, and, an emergency diesel fired generator.

NO_X emissions will be controlled by Dry Low NO_X combustors. The two simple cycle units must meet an emission limit of 9 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2). NO_x emissions from the combined cycle unit will be further controlled by selective catalytic reduction (SCR) to achieve 2.5 ppmvd at 15% O_2. Emissions of CO will be controlled to 7.4 ppmvd @15% O_2.

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

The combined maximum emissions from the four units in tons per year are summarized below. These include the minor emissions from the emergency diesel engines and the cooling towers.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10} (filterable plus condensable)	120	25/15
CO	346	100
NO_X	654	40
VOC	46	40
SO_2	145	40
Sulfuric Acid Mist	15.1	7

Maximum predicted air quality impacts due to emissions from the South Pond project are less than the applicable PSD Class II significant impact levels. Maximum predicted air quality impacts due to emissions from the South Pond Energy Park project are less than the applicable PSD Class I significant impact levels in Chassahowitzka National Wilderness Area located 135 km northwest of the facility.

A CALPUFF modeling analysis for the South Pond project was submitted to the Fish and Wildlife Service (FWS) by the applicant. On the basis of the submittal, the FWS advised the Department "the South Pond project is not expected to significantly impact air quality or visibility at the Chassahowitzka National Wilderness Area."

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 project is not subject to Section 403.501-518, F.S., Florida Electrical Power Plant Siting Act, based on information regarding gross electrical power generated from the steam cycle submitted by the applicant and reviewed by the Department.

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 Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair

Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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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:

Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southwest District Office
111 S. Magnolia Drive, Suite 4	3804 Coconut Palm Drive
Tallahassee, Florida 32301	Tampa, Florida 33619-8218
Telephone: 850/488-0114	Telephone: 813/744-6100
Fax: 850/922-6979	Fax: 813/744-6084

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, Title V Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

South Pond Energy Park, LLC

South Pond Energy Park
600 MW Electrical Power Plant
Hardee County

Facility I.D. No. 0490046-001-AC
PSD-FL-306

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

October 12, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

South Pond Energy Park, LLC
111 Market Place, Suite 200
Baltimore, Maryland 21202

Authorized Representative: Mr. Richard L. Wolfinger

1.2 Reviewing and Process Schedule

11-17-00: Date of Receipt of Application
05-14-01 Application deemed complete
10-12-01: Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

This new facility is located two miles south of Ft. Green on Ft. Green Road in Ft. Green, Hardee County. This site is approximately 135 kilometers southeast of the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates are Zone 17, 407.6 km E, 3048.2 km N.

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

South Pond Energy Park, LLC, a Constellation Power Service Company, proposes to license, construct, and operate a nominal 600 megawatt independent power production facility, referred to as the South Pond Energy Park, in an unincorporated area of Hardee County, Florida. The project consists of three General Electric 7FA combustion turbines that will use dry low-nitrogen oxide combustion technology when operating on natural gas and water injection [for nitrogen oxide control and power augmentation] when operating on distillate fuel oil. One combustion turbine will be in a one-on-one combined cycle operation with a heat recovery steam generator and a steam turbine. The combined cycle unit will be installed with selective catalytic reduction to further reduce emissions of nitrogen oxides. In addition, the combined cycle unit will have the capability of operating in the simple cycle mode. Two additional single GE Frame 7FA combustion turbines will be in simple cycle configuration as peaking units. The primary fuel for the combustion turbines will be natural gas with distillate fuel oil [0.05 percent sulfur] used as a backup fuel. The facility will also have an auxiliary, natural gas fired, boiler which will be used to heat natural gas for the combustion turbines and a 2.8 million gallon fuel oil storage tank.

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC), or sulfuric acid mist (SAM), exceeds 100 tons per year (TPY). The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because proposed emissions will be greater than 100 TPY for PM/PM_{10}, SO_2, CO and NO_X, the facility is also classified a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

As a Major Facility, project emissions greater than the Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}, 7 TPY of SAM) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72 and must apply for an Acid Rain Permit at least 24 months prior to start up.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

ID	EMISSION UNIT DESCRIPTION
001	**Simple Cycle Unit 1** consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW.
002	**Simple Cycle Unit 2** consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW.
003	**Combined Cycle Unit No. 3** consists of a natural gas fired 174 MW gas turbine-electrical generator set, an unfired heat recovery steam generator, and a steam turbine-electrical generator with a capacity of less than 75 MW. The turbine can also operate in the simple cycle mode.
004	**Auxiliary Boiler** consists of an 84 MMBtu/hr, natural gas fired Nebraska Boiler Company boiler.
005	**2.8 Million Gallon Fuel Oil Storage Tank.**

South Pond Energy Park, LLC, a Constellation Power Source Company, proposes to construct a nominal 600 MW electrical power plant in an unincorporated area near Fort Green, in Hardee County.

The new power plant will be a natural gas-fired combustion turbine generator (CTG) facility comprised of one combined cycle (CC) CTG with a nominal generating capacity of 174 MW, and two simple cycle (SC) CTGs each with a nominal generating capacity of 174 MW. The CC unit will consist of one nominal 174 MW CTG, one unfired heat recovery steam generator (HRSG), and one steam turbine-electrical generator (STG) constrained to generate less than 75 MW. The facility will also have an emergency diesel powered fire pump and emergency generator.

The three CTGs will use dry low-nitrogen oxide (DLN) combustion technology when operating on natural gas and water injection when operating on distillate fuel oil. The CC unit will be installed with selective catalytic reduction (SCR) to reduce emissions of nitrogen oxides. Ancillary emission units include, an 84 million Btu auxiliary boiler, a 2.8 million gallon fuel oil storage tank, an emergency diesel powered fire pump, and, an emergency diesel fired generator The CC CTG/HRSG unit will be capable of continuous operation at baseload for up to 8760 hr/yr. The two SC CTG will each be capable of continuous operation at baseload for up to 3,390 hr/yr.

Each turbine will have a nominal heat input rating of 1,743 million Btu per hour (mmBtu/hr), lower heating value (LHV), while firing natural gas at 35°F while operating at 100% load.

The turbine equipped with DLN and SCR will control NO_X emissions to 2.5 parts per million by volume, dry, at 15% O_2 (ppmvd) while burning natural gas and operating in combined cycle mode and the turbines equipped with DLN will control NO_X emissions to 9 ppmvd while operating in simple cycle mode.

Significant emission increases will occur for CO, SO_2, sulfuric acid mist (SAM), PM/PM_{10}, and NO_X. VOC fell below the significant emissions increase level following the application of BACT.

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

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

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

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the South Pond Energy Park, LLC project, one unit will operate in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine, which also drives an electrical generator. Two additional units will operate in simple cycle mode.

South Pond Energy Park, LLC will employ dry low-nitrogen oxide (DLN) combustion technology when operating on natural gas and water injection when operating on distillate fuel oil. The combined cycle unit will also have a selective catalytic reduction (SCR) reactor installed in the HRSG to further reduce emissions of nitrogen oxides.

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Hardee County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, SO_2, SAM, VOC and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO, SO_2, SAM, VOC and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

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

5.1 State Regulations

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

5.2 Federal Rules

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

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, sulfuric acid mist, and negligible quantities of, mercury, lead fluorides, total reduced sulfur and reduced sulfur. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and the Specific Conditions of Draft Permit PSD-FL-306.

6.2 Emission Summary

The emissions for all PSD pollutants as presented in the application for this facility are presented below:

FACILITY EMISSIONS (TOTAL TPY) AND PSD APPLICABILITY

Pollutants	Gas Firing	Total[1]	PSD Significance	PSD REVIEW?
PM/PM_{10}	92/92	120/120	25/15	Yes
SO_2	41.2	145	40	Yes
NO_X	338	654	40	Yes
CO	251	346	100	Yes
Ozone (VOC)	37.1	46	40	Yes
Sulfuric Acid Mist	11.8	15.1	7	Yes
Mercury	NEG	0.0025	0.1	No
Lead	NEG	0.022	0.6	No
Fluorides	NEG	0.067	3	No
Total Reduced Sulfur	NEG	NEG	10	No
Reduced Sulfur Compounds	NEG	NEG	10	No
HAPs[2]			NA	NA

1. Based on emissions from operating at base load at 59°F; firing natural gas for 8,040 hrs in the combined cycle unit and 2,670 hrs in the simple cycle units, and 720 hrs distillate fuel oil in all units. Includes the auxiliary boiler.
2. Less than 10 TPY for any single HAP and less than 25 TPY for all HAPs. Case-by-case MACT does not apply.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of inherently clean fuels. During gas operation, the combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The DLN combustors will control combustion turbine emissions of CO to 9 ppmvd and NO_X to 9 ppmvd @15% O_2 between 50 and 100% of full load under normal operating conditions and during gas burning. Further control for NO_X will be achieved by SCR to 2.5 (combined cycle operation) ppmvd @15% O_2. A full discussion is given in the Draft Best Available Control Technology (BACT)

Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2 and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments or AAQS for SAM.

The applicant's initial PM/PM_{10}, CO, NO_X and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS impact and PSD increment analyses for these pollutants were not required. Also, the maximum predicted impacts for all of the pollutants listed above were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project were the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_X;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Based on these required analyses, 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. However, the following EPA-directed stack height language is included: "In approving this permit, 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.

6.4.2 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. When available, the use of existing representative monitoring data may satisfy the monitoring requirement. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. The table below shows that predicted ambient impacts from the power plant are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

PREDICTED MAXIMUM AIR QUALITY IMPACTS FROM THE PROJECT
COMPARED TO THE DE MINIMIS AMBIENT IMPACT LEVELS

Pollutant	Averaging Time	Max. Predicted Impact, ug/m^3	De Minimis Level, ug/m^3	Impact > De Minimis?
PM_{10}	24-hour	3.3	10	NO
NO_2	Annual	0.8	14	NO
SO_2	24-hour	3.4	13	NO
CO	8-hour	76	575	NO

6.4.3 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 National Weather Service (NWS) stations at Tampa, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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 Chassahowitzka National Wilderness Area (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 14 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. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

6.4.4 Significant Impact Analysis

Typically, in order to conduct a significant impact analysis, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas. If this modeling at worst load conditions shows significant impacts, additional modeling that includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant does not have to conduct any further modeling.

The significant impact analysis submitted for this project contained two separate analyses; one for the surrounding Class II Area, and another for the CNWA, which is the nearest Class I Area. The following paragraphs explain the results of these two analyses:

PSD Class II Area

Over 700 receptors were placed along the facility's restricted property line and out to 30 km from the facility, which is located in a PSD Class II area. The fence line receptors consisted of discrete Cartesian receptors spaced at 100 meter intervals around the facility fence line. The table below shows the results of the significant impact modeling for the Class II Area:

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.1	1	NO
	24-Hour	3.4	5	NO
	3-Hour	12.7	25	NO
PM_{10}	Annual	0.1	1	NO
	24-Hour	3.3	5	NO
CO	8-Hour	76	500	NO
	1-Hour	208	2000	NO
NO_2	Annual	0.8	1	NO

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project; therefore, no further modeling was required in the surrounding Class II Area.

PSD Class I Area

The Chassahowitzka National Wilderness Area (CNWA) is the closest PSD Class I Area, and is located approximately 135 km northwest of the project. Pollutant concentrations were predicted at 13 discrete receptors chosen by the Department. The maximum predicted impacts for all applicable pollutants due to the proposed project were compared to the Class I significant impact levels to determine whether there was a significant impact in the CNWA. The table below shows the results of the Class I significant impact modeling:

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (CNWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.01	0.1	NO
	24-Hour	0.1	0.2	NO
	3-Hour	0.4	1.0	NO
PM_{10}	Annual	0.003	0.2	NO
	24-Hour	0.1	0.3	NO
NO_2	Annual	0.004	0.1	NO

The results of the significant impact modeling revealed that there were no significant impacts predicted due to the emissions from this project in the CNWA Class I Area. Therefore, no further modeling was required for this project in the CNWA.

6.4.5 Additional Impacts Analysis

Impact On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired 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 expected to be minor. Ammonia emissions will result as a result of NO_X control. The impacts of ammonia on soils, vegetation, and wildlife will be in the same range as the effects of NO_X on the same media.

Nearby fertilizer operations are a larger source of SO_2 and sulfuric acid mist emissions and use large quantities of ammonia. The impacts from the South Pond project on non-air media will be smaller by comparison.

Impact On Visibility

Natural gas is a clean fuel and produces little particulate emissions. The low NO_X and SO_2 emissions will also minimize plume opacity. A regional haze analysis for the CNWA was submitted by the applicant. Based on federal land manager (U.S. Fish and Wildlife Service) criteria, no adverse impacts were predicted.

The effects on visibility due to additional particulate matter from ammonia use are very difficult to quantify. These will be minimized by limiting ammonia emissions (slip) to 5 ppmvd.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the combustion turbine will require few permanent employees, which will cause no significant impact on the local Area.

This project is a response to state-wide 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," and the lowest air emissions per unit of electric power generating capacity.

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.

7. CONCLUSION

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

Scott M. Sheplak, P.E.
Edward J. Svec, Review Engineer
Cleve Holladay, Meteorologist

South Pond Energy Park, LLC
PSD-FL-306 and 0490046-001-AC
Hardee County, Florida

BACKGROUND

The applicant, South Pond Energy Park, LLC, proposes to install/construct a 600 MW power plant at a new facility located two miles south of Ft. Green on Ft. Green Road in Ft. Green, Hardee County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), volatile organic compounds (VOC) and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new power plant will be a natural gas-fired combustion turbine generator (CTG) facility comprised of one combined cycle (CC) CTG with a nominal generating capacity of 174 MW, and two simple cycle (SC) CTGs each with a nominal generating capacity of 174 MW. The CC unit will consist of one nominal 174 MW CTG, one unfired heat recovery steam generator (HRSG), and one steam turbine-electrical generator (STG) constrained to generate less than 75 MW. Ancillary emission units include an auxiliary boiler and a 2.8 million gallon fuel oil storage tank. The CC CTG/HRSG unit will be capable of continuous operation at baseload for up to 8760 hr/yr. The two SC CTG will each be capable of continuous operation at baseload for up to 3,390 hr/yr.

The project also includes an emergency diesel powered fire pump and an emergency diesel fired generator. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated September 10, 2001, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on November 17, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Golder Associates Inc.

REVIEW GROUP MEMBERS:

Edward J. Svec, Permit Engineer and Scott M. Sheplak, P.E.

BACT REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	3.5 ppmvd @15% O_2 (gas) CC 9 ppmvd @15% O_2 (gas) SC
Carbon Monoxide	Combustion Controls	9 ppmvd @15% O_2 (gas)
SO_2 and Sulfuric Acid Mist	Inherently Clean Fuels Combustion Controls	Natural Gas and 0.05% S No. 2 Fuel Oil
Volatile organic Compounds		2.0 ppmvd @15% O_2 (gas)
Particulate Matter	Inherently Clean Fuels Combustion Controls	10 pounds per hour

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the South Pond Energy Park, LLC is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency unit to be purchased by South Pond Energy Park, LLC. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

There is a National Emission Standard for Hazardous Air Pollutants (NESHAP) under development by EPA, but it is not applicable to this project. Because emissions of HAP are less than 10 tons per year, there is no requirement to conduct a case-by-case maximum achievable control technology determinaion.

DETERMINATIONS BY STATES:

The following tables are samples of information on some recent applications, proposals, and determinations in the Southeast for simple and combined cycle projects. The South Pond Energy Park, LLC Project is included for reference.

TABLE 1

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

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
South Pond Hardee, FL	600	9 - NG 36 - No. 2 FO	DLN	2X 174 MW GE 7FA CTs. Under Review
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Gas Only
Enron Deerfield, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 500 hrs on oil
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 03/01. 1000 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued. 1687 hrs on oil
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE 7FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous
SC = Simple Cycle
INT = Intermittent

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR

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

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

TABLE 2

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

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
South Pond Hardee, FL	9 (7.4@15% O_2) - NG 20 - FO	1.4 – NG	10 lb/hr – NG	Clean Fuels Good Combustion
El Paso Deerfield, FL	9 (7.4@15% O_2) - NG	1.4 (1.3@15% O2)	18 lb/hr (Front & Back)	Clean Fuels Good Combustion
Enron Deerfield, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA BALDWIN, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

TABLE 3

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

Project Location	Capacity Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
South Pond Hardee, FL	600	2.5 – NG 10 – FO	SCR	1X 174 MW GE 7FA CT. Under Review
El Paso Deerfield, FL	250	2.5 – NG	SCR	175 MW GE 7FA
CPV Pierce, FL	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT 7/2001
Metcalf Energy, CA	600	2.5 – NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce, FL	~250	3.5 – NG 10 - FO	SCR	170 MW MHI501F CT Repowering
CPV Atlantic, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
CPV Gulfcoast, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
TECO Bayside, FL	1750	3.5 – NG 12 - FO	SCR	7x170 MW GE 7FA CTs Repowering
FPC Hines II, FL	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F
Calpine Osprey, FL	527	3.5 – NG	SCR	2x170 MW WH501F Draft 5/00
Calpine Blue Heron, FL	1080	3.5 – NG	SCR	4x170 MW WH501F Draft 2/00
Santee Cooper, SC	~500	9 – NG	DLN	2x170 MW GE 7FA CTs ~ 4/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG (12 – simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
Lake Worth LLC, FL	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98

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

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
CT = Combustion Turbine

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

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

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

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

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as the South Pond Energy Park, LLC.

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

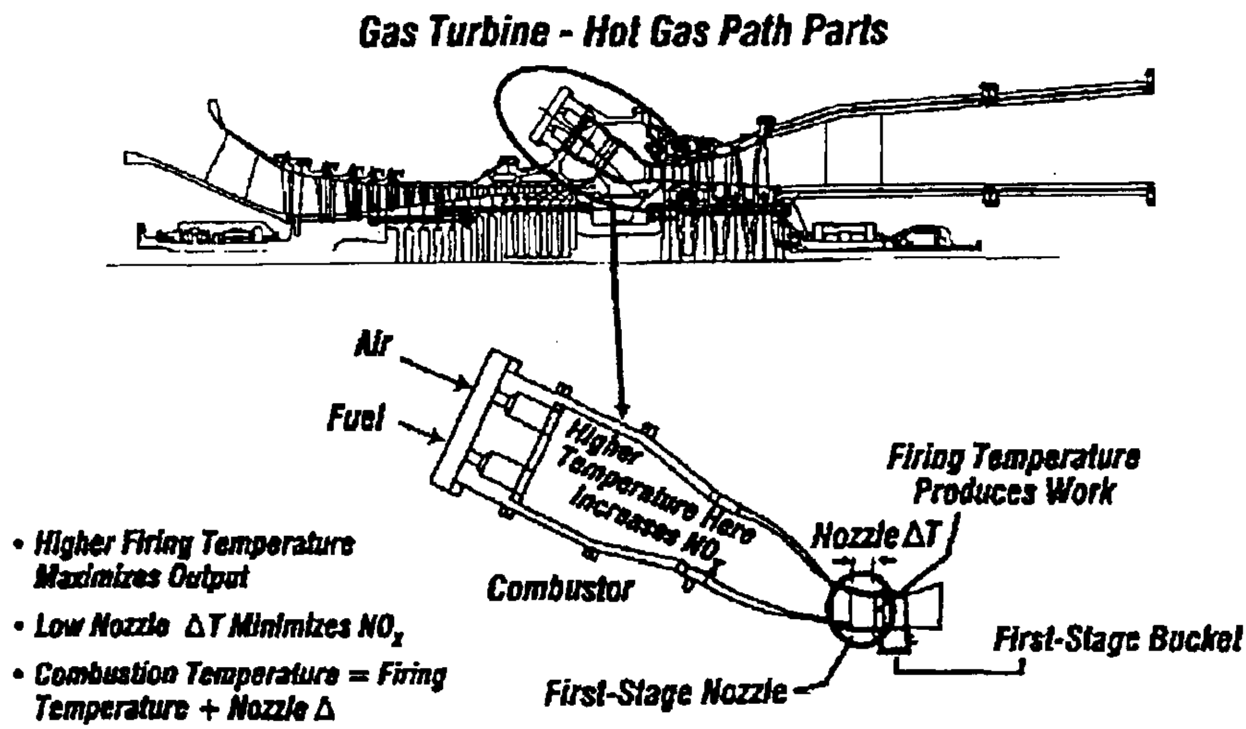

Figure 1 – Relation Between Flame Temperature and Firing Temperature

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN)

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

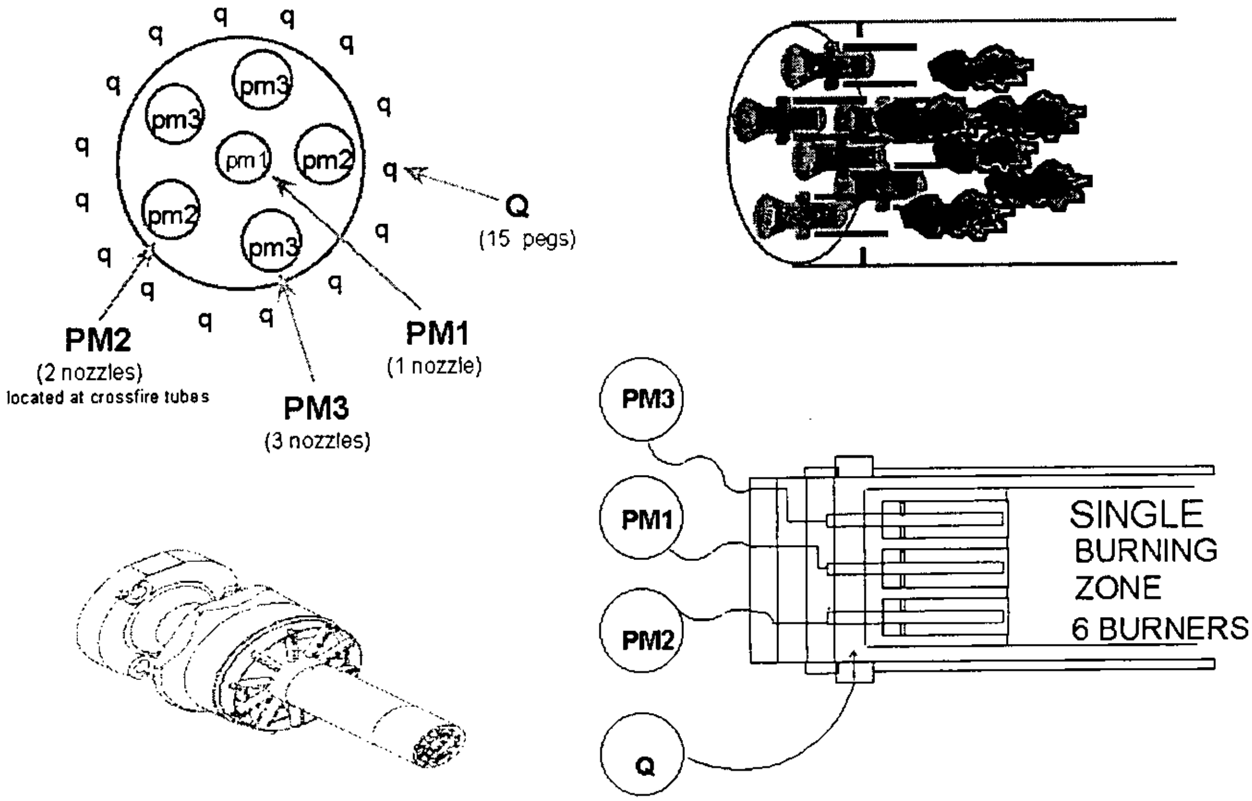

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

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

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

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[1] The DLN-2.6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd. The results are all superior to the emission characteristics given in Figure 3.

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

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

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

Recent conversations with other operators indicate that the "Dry Low NO_X" characteristics extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE.[3]

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

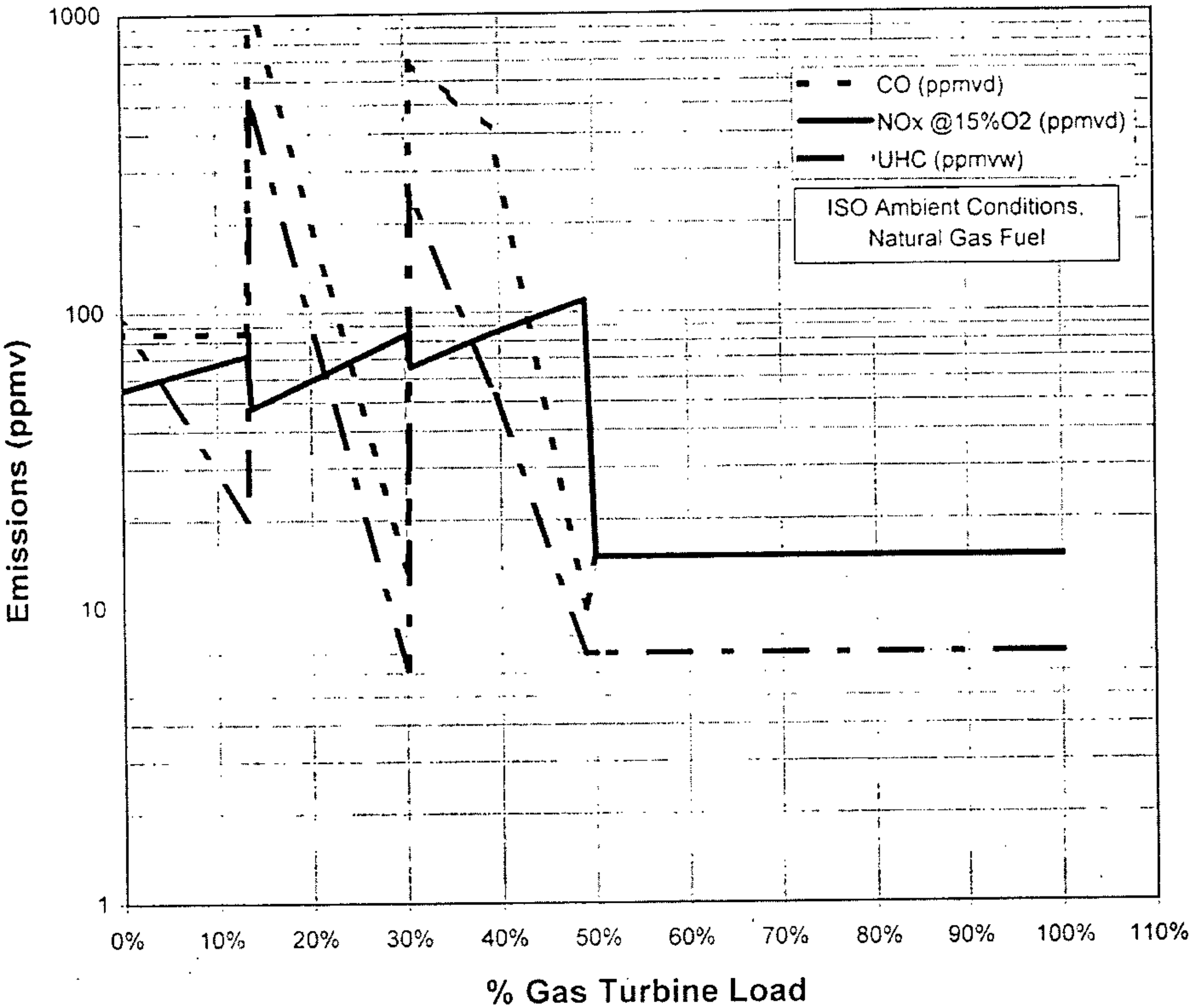

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor

Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_x)

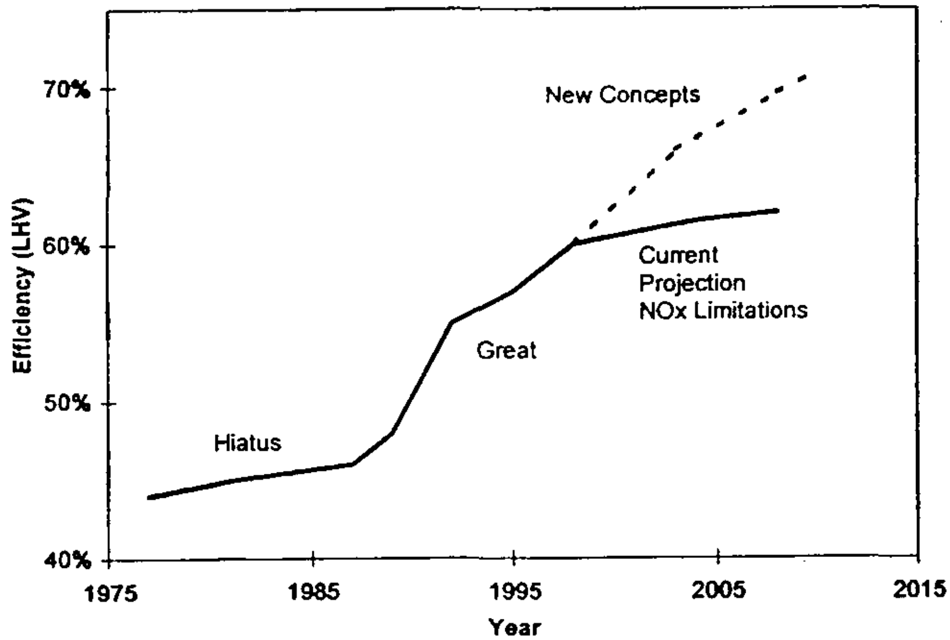

Figure 4 – Efficiency Increases in Combustion Turbines

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

Catalytic Combustion: XONON™

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

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

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

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

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

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

Selective Catalytic Combustion: SCR

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

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

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

Kissimmee Utilities Authority (KUA) will install SCR at the Cane Island Unit 3 project. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued recently to Competitive Power Ventures (CPV), Calpine, Florida Power Corporation, and Tampa Electric to achieve 3.5 ppmvd. More recently a permit was issued to CPV for its Pierce, Polk County project with a limit of 2.5 ppmvd @15% O_2 by SCR.

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

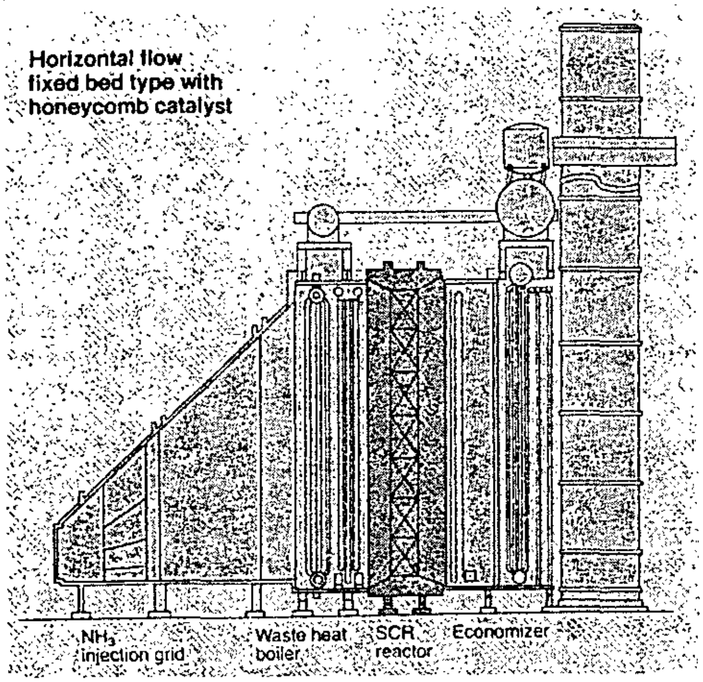

Figure 5 – SCR System within HRSG

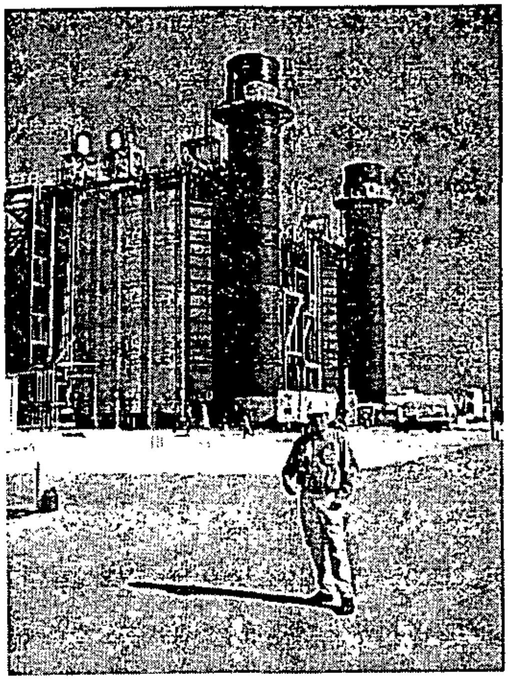

Figure 6 – FPC Hines Power Block I

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

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

$SCONO_X$™

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

California regulators and industry sources stated that the first 250 MW block to install $SCONO_X$™ will be at PG&E's La Paloma Plant near Bakersfield.[9] The overall project includes several more 250 MW blocks with SCR for control.[10] USEPA 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 equipped with $SCONO_X$™.

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

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [11] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmvd. More recently, Goal Line announced that $SCONO_X$™ has in practice achieved emissions of 1.3 ppmvd.[12]

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[13]

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

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

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

For this project, the applicant has proposed as BACT the use of pipeline natural gas. The applicant estimated total emissions for the project at 145 TPY of SO_2 and 15.1 TPY of SAM. The Department expects the emissions to be lower because the typical natural gas in Florida contains less than the 1.5 grains of sulfur per 100 standard cubic feet (gr S/100scf) specification proposed by South Pond Energy Park, LLC. This value is well below the "default" maximum value of 20 gr S/100 scf characteristic of natural gas, but is still high enough to require a BACT determination.

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

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

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

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 120 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

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

CO is emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO. There is a great deal of uncertainty regarding actual CO emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions have actually been reported from several facilities without use of oxidation catalyst. For example, although Westinghouse does not offer a single digit CO guarantee on the 501F, the units installed at the FPC Hines Energy Complex achieved CO emissions in the range of 1-3 ppmvd on both gas and fuel oil at full load.[14] As previously discussed, GE 7FA units achieved similar results when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent.

CO emissions *should* be low (at least at full load) because of the very high combustion temperatures characteristic of "F-Class" turbines. It appears that contract writing has not yet "caught up" with the field experience to consistently guarantee low CO emissions for F-Class units, at least at high loads.

One alternative is to complete the combustion by installation of an oxidation catalyst. Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd.

A recent permit was issued by the Bay Area AQMD in California for the Metcalf Energy Center. The limit for CO from a Siemens-Westinghouse 501F gas turbine is 6 ppmvd (at full load). No Catalyst is required. However it is doubtful that performance can be maintained at low load.

A recent draft permit was issued by the Department that limits CO to 3.5 ppmvd on a Mitsubishi 501F combustion turbine.[15] Enron will install an oxidation catalyst at Ft. Pierce in order to avoid high CO emissions at low load (<70 percent of full load). This results in the ability to obtain a guarantee for the low permitted level at full load. This would not have been a concern if the units were GE7FAs for the reasons discussed above.

The limit proposed by South Pond Energy Park, LLC under normal operation is 9 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil @15% O_2 at all loads. This is consistent with the description of the DLN-2.6 technology.

Total annual emissions of CO for the project are expected to be approximately 346 tons per year.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limit proposed by South

Pond Energy Park, LLC for this project is 2 ppmvd @ 15% O_2 for all modes of operation. According to GE (and Department data), VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[16]

Total annual emissions of VOC for the project at the 2 ppmvd limit requested by the applicant are expected to be approximately 46 tons per year. The annual emissions at 1.4 ppmvd are expected to be below the significant emissions level for VOC.

AUXILIARY BOILER

South Pond Energy Park, LLC proposes the emissions from the auxiliary boiler will be reduced through the use of low NO_X burners, the use of clean fuels, and the application of good combustion practices.

A review of the BACT/LAER Clearinghouse for natural gas fired boilers rated less than 100 million Btu per hour shows BACT for NO_X to be low NO_X burners and boiler design, good combustion practices, and, firing of natural gas to be BACT for carbon monoxide, sulfur dioxide, particulate, and volatile organic compounds.

Total annual emissions for the project are expected to be approximately 36.8 tons per year of NO_X, 73.6 tons per year of CO, and 15.4 tons per year of VOC.

BACKGROUND ON PROPOSED GAS TURBINE

South Pond Energy Park, LLC plans to install three nominal 174-MW General Electric 7FA gas turbines, one of which will operate in combined cycle mode. Per the discussion above, such units are capable of achieving and have achieved (with DLN and SCR technology) all of the emission limits proposed by South Pond Energy Park, LLC as BACT.

The GE Speedtronic™ Mark VI Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include fuel control in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark VI also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[17]

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[18] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

RESULTS OF INITIAL COMPLIANCE TESTS ON NATURAL GAS AT TECO POLK POWER STATION UNIT 2

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

RESULTS OF INITIAL COMPLIANCE TESTS ON FUEL OIL TECO POLK POWER STATION UNIT 2

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	35.6	3.0	<0.1
70	38.6	2.7	<0.1
85	38.2	2.2	<0.1
100	41.5	1.1	<0.1
Limit	42	20	3.5

Tests on new GE PG7241FA simple cycle combustion turbines at the FPL Fort Myers Power Plant and the JEA Kennedy Plant confirm the experience from the TECO unit.

RESULTS OF INITIAL COMPLIANCE TESTS ON NATURAL GAS AT FPL FORT MYERS POWER PLANT UNIT 2A

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	6.4	-	-
63	6.6	-	-
87	6.6	-	-
100	8.6	<0.1	<0.1
Limit	9 (30-day)	12	1.4

RESULTS OF INITIAL COMPLIANCE TESTS ON NATURAL GAS AT JEA KENNEDY UNIT KCT-7

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
100	7.7	4.0	0.5*
Limit	15	15	1.4

* Methane (not a VOC) was not subtracted from VOC reported

RESULTS OF INITIAL COMPLIANCE TESTS ON FUEL OIL AT JEA KENNEDY UNIT KCT-7

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
100	29.8	2.0	1.1*
Limit	42	15	1.4

The results during the "new and clean" test of the GE PG7241 at these plants are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits.

Values while burning oil were equally good in comparison to the permitted limits for CO and VOC, while the NO_X emissions were close to the permitted value of 42 ppmvd @15% O_2. The results of the NO_X tests at the JEA Kennedy Plant while burning oil suggest that values less than 42 ppmvd can be attained and possibly maintained. Visible emissions were 0 percent opacity at all of the units when firing natural gas or fuel oil.

STARTUP AND SHUTDOWN EMISSIONS

The Department defines "Startup" as follows[19]:

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

The Department permits excess emissions during startup and shut down as follows:[20]

Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

The Department defines "Excess Emissions" as follows:[21]

"Excess Emissions" - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4,

F.A.C. The term applies only to conditions which occur during startup, shutdown, sootblowing, load changing or malfunction.

The U.S. EPA Region IV office recently recommended that the Department consider "establishment of startup and shutdown BACT for CO and NO_X such as mass emission limits (e.g., pounds of emissions in any 24-hour period) that include startup and shutdown emissions, or future emission limits derived from monitoring results during the first few months of commercial operation."[22]

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

A review of published General Electric information indicates that features are incorporated into the design of the DLN-2.6 technology specifically aimed at minimizing emissions. One of the key elements was to incorporate lean pre-mixed burning while operating the unit in low load and startup.[23] This is in contrast with the previous DLN-2.0 technology that relied on diffusion mode combustion at four of the burners in each combustor during startup and low load operation.

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

Within the following 5 minutes, the unit switches to Mode 5 (or 5 Q), during which NO_X concentrations are typically less than 10 ppmvd even though the unit is not yet at full load.[24] The Low-NO_X modes occurs when at least the five outer nozzles are in operation.

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

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

For a combined cycle cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated up. During a period of approximately 2 hours emissions will be roughly 60 to 80 ppmvd NO_X @15% O_2. Once the HRSG is heated sufficiently, the ammonia system is turned on to abate emissions.

While emissions during the first two or three hours may be greater than during full load steady state operation, such startups are infrequent. Also, it is noted that such a cold startup would be preceded by a shutdown of at least 48 hours. Therefore the startup emissions would not cause annual emissions greater than the potential-to-emit under continuous operation.

The combined cycle startup scenario described above can be modified by use of a bypass stack and damper.[25] Under this scenario, the steam cycle can be slowly brought up to load while the gas turbine reaches full load as fast as it would under simple cycle mode. The exhaust gas can be modulated in such a fashion that the HRSG and steam turbine are ramped up slowly in accordance with their respective specifications. At the same time, the gas turbine will quickly accelerate to the DLN modes (5Q or 6Q) thus minimizing emissions. In this manner the startup NO_X and CO concentrations are reduced to the values observed during simple cycle startup. Thereafter the unit will exhibit the same characteristics (for about two hours) as a simple cycle unit in steady-state operation until the ammonia system is actuated.

Implementation of bypass modulation requires an additional stack and design features to minimize stratification and uneven heating of boiler tube bundles in the HRSG.

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

DEPARTMENT BACT DETERMINATION

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

POLLUTANT	CONTROL TECHNOLOGY	DEPARTMENT'S PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X, Water Injection, limited oil use (SC) Selective Catalytic Reduction (CC) Low NO_X Burner (Auxiliary Boiler)	9 NG / 36 FO ppmvd @ 15% O_2 (simple cycle units) 2.5 NG / 10 FO ppmvd @ 15% O_2 (combined cycle) 5 ppm ammonia slip from combined cycle unit 8.4 pounds per hour Auxiliary Boiler
Particulate Matter	Pipeline Natural Gas Combustion Controls	10 pounds per hour (front-half catch)
Visible Emissions	As Above	10 Percent (surrogate for PM_{10})
Carbon Monoxide	As Above	7.4 ppmvd @15% O_2 (full load) NG 20 ppmvd No. 2 FO 16.8 pounds per hour Auxiliary Boiler
Sulfur Oxides Sulfuric Acid Mist	As Above	1.5 grain sulfur/100 std cubic feet NG 0.05% S, by weight FO
Volatile Organic Compounds	As Above	1.4 ppmvd NG 3.5 pounds per hour Auxiliary Boiler

RATIONALE FOR DEPARTMENT'S DETERMINATION

- Certain control options are feasible only for combined cycle units are not applicable to simple cycle operation. This rules out Low Temperature (conventional) SCR, and $SCONO_X$. XONON is claimed to be available for F Class gas-fired projects.

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are high temperature (Hot) SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- The levelized costs of NO_X removal by Hot SCR for the South Pond Energy Park project were estimated by South Pond Energy Park at $13,413 per ton. The estimates are based on reducing NO_X emissions from 9 to 3.5 ppmvd @15% O_2.
- The Department does not necessarily accept the precise Hot SCR cost calculations presented by South Pond Energy Park but believes the costs are certainly greater than $10,000 per ton. Even at $10,000 per ton, the Department would agree that Hot SCR is not cost-effective for this project.
- XONON is rejected because it has not yet been demonstrated in large combustion turbines and is likely to be even less cost-effective than Hot SCR.
- The Department accepts South Pond Energy Park's BACT proposal of 9 ppmvd NO_X @15% O_2 for the simple cycle units while combusting natural gas. The Department notes that data from the City of Tallahassee and TECO demonstrate that the GE 7FA units actually achieve 6 to 8 ppmvd @15% O_2.
- The Department will limit operation of the two simple cycle units to an average of 3,390 hours per year per unit of which 500 hours per year per unit may be on No. 2 distillate fuel oil.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out the possibility of $SCONO_X$. XONON is claimed to be available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.
- The 9-ppmvd @15% O_2 limit at DBE while firing natural gas is equal to the lowest BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty.
- The gas-based NO_X emission limit of 9 ppmvd @15% O_2 will be difficult to maintain over short term averaging times. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually

exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion. The permit includes limited periods of data to be excluded from the NO_X CEMS compliance averages due to startup, shutdown and unavoidable malfunction.

- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. Applicants have advised that GE will not guarantee less than 42 ppmvd @15% O_2.
- In 1999, the Department requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[26] GE did not respond to the request.
- Based on compliance test results at the JEA Kennedy Plant, it is possible that the NO_X emissions while firing oil from may be reduced from 42 to 30 ppmvd @15% O_2. Interestingly, 30 ppmvd @15% O_2 corresponds to approximately 42 ppmvd uncorrected.
- The Department's overall BACT determination for natural gas firing is equivalent to approximately 0.35 lb of NO_X per megawatt-hour (lb/MWH) by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a (fuel independent) limit of 1.6 lb/MW-hr. The value while firing back-up fuel oil is approximately 1.75 lb/MWH based on Enron's proposal and 1.5 lb/MWH based on the Department's determination.
- Although startup and shutdown emissions are generally exempt, emissions during startup and shutdown are less than the NSPS limit of 110 ppmvd @15% O_2 (that applies during steady-state operation).
- The Department does not yet have sufficient information from field experience to set start-up and shutdown emissions limits. However, the modes that give rise to high NO_X concentration have been identified. The Department will therefore set a work practices standard as BACT.
- The Work Practice BACT for simple cycle startup is that the unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. The shutdown case is trivial.
- The Lowest Achievable Emission Rate (LAER) for a combined cycle unit is approximately 2 ppmvd NO_X at 15 percent oxygen (@15% O_2) while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line, has requested recognition of a 1.3 ppmvd NO_X value as *achieved in practice*.
- There are several projects for large turbines in Massachusetts, Connecticut, New York, and California requiring SCR with a NO_X emission limit of 2 ppmvd @15% O_2.
- The "Top" technology in a top/down analysis for a combined cycle unit will achieve approximately 2 ppmvd @15% O_2 by either $SCONO_X$ or SCR.

- South Pond Energy Park estimated the cost effectiveness of $SCONO_X$ at $21,345 per ton of NO_X removed. The Department does not necessarily accept the precise $SCONO_X$ cost calculations presented by South Pond Energy Park. However, even at half the cost estimated by South Pond Energy Park, the Department agrees that $SCONO_X$ would not be cost-effective for this project.
- South Pond Energy Park estimated the cost-effectiveness of conventional (cold temperature) SCR at $5,511 per ton of NO_X while reducing emissions from 9 to 3.5 ppmvd @15% O_2. The Department believes that South Pond Energy Park's estimate is on the high side, but is nevertheless cost-effective. Furthermore, the Department believes cost-effectiveness can be maintained while achieving an NO_X emission rate of 2.5 ppmvd @15% O_2.
- The Fish and Wildlife Service advised in its review of the application that BACT determinations of 2.5 ppmvd NO_X @15% O_2 have recently been issued for combined cycle projects in Maine and Washington. The Fish and Wildlife Service also agreed that 9 ppmvd represents BACT for simple cycle units.[27]
- The Department concludes that 2.5 ppmvd NO_X @15% O_2 (with 5 ppmvd ammonia slip) while firing natural gas in a combined cycle unit constitutes BACT. This value for the conventional SCR option takes into consideration the measurement uncertainties at low emission rates and minimizes particulate emissions due to ammonia emissions.
- The effects of aqueous ammonia use and ammonia slip are not unacceptable.
- The Department's overall BACT determination for the combined cycle unit is less than 0.07 lb of NO_X per megawatt-hour (lb/MWH) by Dry Low NO_X.
- The Work Practice BACT for combined cycle startup is that the combustion turbine will start up and operate as a simple cycle unit and modulate exhaust to the HRSG. This requires installation of a bypass stack and damper. The unit shall reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. Ammonia injection will be practiced within three hours after gas turbine ignition and crossfire.
- The Department does not have a cost estimate for the additional stack and design requirements, but believes the additional power and flexibility offered by full load simple cycle operation during the cold startup of the steam cycle more than compensates for the additional costs.
- The Department estimates VOC emissions of 1.4 ppmvd @15% O_2 (or less) for all firing modes. These levels will avoid triggering PSD or a requirement for a BACT determination.
- South Pond Energy Park estimated levelized costs at $9,929 per ton to reduce emissions at the simple cycle units from about 7.4 to 0.7 ppmvd CO @15% O_2. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- In view of the performance of GE 7FA units without add-on control (~ 0 - 4 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective for the simple cycle units based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will set CO limits achievable by good combustion at full load as 7.4 ppmvd @15% O_2 (full load) (gas) and 20 ppmvd (oil). These values are in the lower range of values

from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.

- The Department will set CO limits reflecting the "new and clean test" guarantees rather than actual performance because GE will not (yet) guarantee the lower values. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.
- There is no benefit in penalizing the applicant with a lower limit at this time just because the performance at another site was far better than guaranteed or expected. The applicant will be required to install a continuous CO monitor on the combined cycle unit. It is expected that data from continuous measurement will conclusively show that oxidation catalyst is not needed and is not cost effective for this project.
- BACT for sulfur oxides is the exclusive use of natural gas with a specification of 1.5 grains per 100 standard cubic feet. Pipeline quality natural gas in Florida contains less than this value.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering, exclusive use of pipeline natural gas, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limit for PM_{10} will be set at 10 pounds per hour. This value is based on filterable fraction only per the Department's definition of PM/PM_{10}. Expected particulate emissions based on filterable plus condensable particulate matter are 20 pounds per hour.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.
- BACT for the Auxiliary Boiler was determined to be the use of clean fuels and a low NO_X burner limiting NO_X emissions to 8.4 pounds per hour and the use of good combustion practices which will limit CO to 16.8 pounds per hour and VOC to 3.5 pounds per hour.

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POLLUTANT	COMPLIANCE PROCEDURE
PM/PM_{10} (Visible Emissions)	Conduct initial, concurrent Method 5 and 9 tests and annual Method 9 tests. Thereafter, fuel specifications and CO/VE limits serve as surrogate limits.
CO	Conduct initial and annual Method 10 tests.
NO_X (Initial)	Conduct initial Method 20 (or 7E) tests.
NO_X (Continuous)	Continuous compliance demonstrated by data collected from NO_X CEMS and diluent monitors (O_2 or CO_2). A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Pursuant to Rule 62-210.700 F.A.C., up to 2 hourly averages in a 24-hour block may be excluded due to startups and shutdowns. Up to 2 hourly averages in a 24-hour block may be excluded due to unavoidable malfunction. A separate compliance determination is conducted at the end of each operating day, which is calculated from the arithmetic average of all valid hourly emission rates. May use data collected during RATA if performed at capacity.
SO_2 and SAM	Maintain records of fuel sampling and analysis with appropriate ASTM Methods.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Edward J. Svec, Review Engineer, Title V Section
Scott M. Sheplak, P.E. Administrator, Title V Section
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

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DRAFT PERMIT

PERMITTEE:

South Pond Energy Park, LLC
111 Market Place, Suite 200
Baltimore, Maryland 21202

Authorized Representative:
Mr. Richard L. Wolfinger, Vice President

Facility Name:	South Pond Energy Park
Project No.	0490046-001-AC
Air Permit No.	PSD-FL-306
Facility ID No.	0490046
SIC No.	4911
Expires:	December 1, 2004

PROJECT AND LOCATION

This permit authorizes the construction of a new nominal 600 MW electrical generating plant, the South Pond Energy Park, LLC, to be located approximately two miles south of Ft. Green on Ft. Green Road in Ft. Green, Hardee County, Florida. The plant will consist of one combined cycle gas turbine, two simple cycle gas turbines, and associated equipment. The UTM coordinates are Zone 17, 407.6 km East, and 3,048.2 km North.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Section I. General Information
Section II. Administrative Requirements
Section III. Emissions Units Specific Conditions
Section IV. Appendices BD, GG, GC, and XS (made part of the permit)

(DRAFT)

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Howard L. Rhodes, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The proposed project is for a new electrical power plant, the South Pond Energy Park, LLC, which will generate a nominal 600 MW of electricity. The plant will consist of one combined cycle gas turbine unit (174 MW, total) and two simple cycle gas turbine units (174 MW, each).

NEW EMISSIONS UNITS

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

ID	EMISSION UNIT DESCRIPTION
001	**Simple Cycle Unit 1** consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW.
002	**Simple Cycle Unit 2** consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW.
003	**Combined Cycle Unit No. 3** consists of a natural gas fired 174 MW gas turbine-electrical generator set, an unfired heat recovery steam generator, and a steam turbine-electrical generator with a capacity of less than 75 MW. The turbine can also operate in the simple cycle mode.
004	**Auxiliary Boiler** consists of an 84 MMBtu/hr, natural gas fired Nebraska Boiler Company boiler.
005	**2.8 Million Gallon Fuel Oil Storage Tank**.

REGULATORY CLASSIFICATION

Title III: Based on available data, the new facility is a major source of hazardous air pollutants (HAP).

Title IV: The new gas turbines are subject to the acid rain provisions of the Clean Air Act.

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

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

PPSC: This project is not subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because it produces less than 75 MW of steam generated electrical power.

NSPS: The new gas turbines are subject to the New Source Performance Standards of 40 CFR 60, Subpart GG. The new auxiliary boiler is subject to the New Source Performance Standards of 40 CFR 60, Subpart Dc. The new fuel storage tank is subject to the New Source Performance Standards of 40 CFR 60, Subpart Kb.

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are high temperature (Hot) SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- The levelized costs of NO_X removal by Hot SCR for the South Pond Energy Park project were estimated by South Pond Energy Park at $13,413 per ton. The estimates are based on reducing NO_X emissions from 9 to 3.5 ppmvd @15% O_2.
- The Department does not necessarily accept the precise Hot SCR cost calculations presented by South Pond Energy Park but believes the costs are certainly greater than $10,000 per ton. Even at $10,000 per ton, the Department would agree that Hot SCR is not cost-effective for this project.
- XONON is rejected because it has not yet been demonstrated in large combustion turbines and is likely to be even less cost-effective than Hot SCR.
- The Department accepts South Pond Energy Park's BACT proposal of 9 ppmvd NO_X @15% O_2 for the simple cycle units while combusting natural gas. The Department notes that data from the City of Tallahassee and TECO demonstrate that the GE 7FA units actually achieve 6 to 8 ppmvd @15% O_2.
- The Department will limit operation of the two simple cycle units to an average of 3,390 hours per year per unit of which 500 hours per year per unit may be on No. 2 distillate fuel oil.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out the possibility of $SCONO_X$. XONON is claimed to be available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.
- The 9-ppmvd @15% O_2 limit at DBE while firing natural gas is equal to the lowest BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty.
- The gas-based NO_X emission limit of 9 ppmvd @15% O_2 will be difficult to maintain over short term averaging times. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITIES

All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District Office, 3804 Coconut Palm Dr, Tampa, Fl 33619-8218 and phone number 813/744-6100.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix XS. Continuous Monitor Systems Quarterly Report

RELEVANT DOCUMENTS

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

- Permit application received on 11/17/00 and all related correspondence to make complete.
- Draft permit package issued on (Draft)
- Comments received from the EPA Region 4 Office, and the Fish and Wildlife Service.

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

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

3. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

4. Completion of Construction: The permit expiration date is December 1, 2004. Physical construction shall be completed by September 1, 2004. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

5. Permit Expiration Date Extension: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

6. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

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

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

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

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

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

Emissions Unit 003: Combined Cycle Unit No. 3
Description: The combined cycle unit consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set with a capacity of less than 75 MW. Ancillary equipment includes an automated gas turbine control system, and an inlet air filtration system. The turbine can also operate in the simple cycle mode.
Fuel: The combined cycle unit is fired with pipeline-quality natural gas as the primary fuel, with No. 2 fuel oil as the standby fuel.
Capacity: At a compressor inlet air temperature of 35° F, the combined cycle gas turbine produces 174 MW when firing approximately 1,609 MMBtu (LHV) per hour of natural gas and 183 MW when firing approximately 1,803 MMBtu (LHV) per hour of distillate fuel oil.
Controls: The efficient combustion of pipeline-quality natural gas at high temperatures minimizes emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces NOx emissions.
Stack Parameters: When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit a 150 feet tall stack that is 19.0 feet in diameter with a flow rate of approximately 1,006,700 acfm at 200° F.

APPLICABLE STANDARDS AND REGULATIONS

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

EQUIPMENT

2. Combined Cycle Gas Turbine: The permittee is authorized to install, tune, maintain and operate a new combined cycle unit consisting of a General Electric Frame 7FA gas turbine-electrical generator set, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set. The combined cycle unit shall be designed as a system to generate a nominal 174 MW of shaft-driven electrical power and less than 75 MW of steam generated electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, and a single exhaust stack that is 150 feet tall and 19.0 feet in diameter, and associated support equipment. [Applicant Request; Design]

3. Continuous Compliance with the 74.9 MW Steam Power Generated Limitation: Electrical power from the steam-electrical generator shall be limited to 74.9 MW on an hourly basis. South Pond Energy Park shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system.

4. DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric dry low-NOx combustion system to control NOx emissions from the combined cycle gas turbine. Prior to the

initial emissions performance tests for each gas turbine, the dry low-NOx combustors and automated gas turbine control system shall be tuned to minimize NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]

5. (SCR) System: The permittee shall install, tune, maintain and operate a selective catalytic reduction (SCR) system to control NOx emissions from the combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, anhydrous ammonia storage, monitoring and control system, electrical, piping and other auxiliary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels. [Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity: The maximum heat input rate to the combined cycle gas turbine shall not exceed 1,609 mmBTU per hour while producing approximately 174 MW at ISO conditions, the lower heating value (LHV) of natural gas, and 100% load; or 1,803 mmBTU per hour while producing approximately 183 MW at ISO conditions, the lower heating value (LHV) of No. 2 fuel oil, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and alternate methods of operation. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Authorized Fuel: The gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.05% by weight. Oil firing shall not exceed 720 hours per year. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

8. Restricted Operation: The hours of operation in the combined cycle mode are not limited (8,760 hours per year). If the turbine is operated in the simple cycle mode, the hours of operation are limited to 3,390 per year. [Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to the combined cycle gas turbine when operating in either the combined cycle or simple cycle mode. Unless otherwise noted, the mass emission limits are based a compressor inlet temperature of 35° F and 100% load. For comparison to the standard, actual measured mass emissions shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

9. Ammonia Slip: Ammonia slip shall not exceed 5 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method CTM-027, when operating in the combined cycle mode. [Rule 62-4.070(3), F.A.C.]

10. Carbon Monoxide (CO)

    a. *Initial Test, Standard Operation*: When operating in either the simple cycle or combined cycle mode, CO emissions shall not exceed 7.4 ppmvd corrected to 15% oxygen when operating on natural gas nor 20 ppmvd corrected to 15% oxygen when operating on distillate fuel oil based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

b. *Continuous Compliance, Standard Operation*: When operating in either the simple cycle or combined cycle mode, CO emissions shall not exceed 7.4 ppmvd corrected to 15% oxygen when operating on natural gas nor 20 ppmvd corrected to 15% oxygen when operating on distillate fuel oil based on a 3-hour block average as determined by valid data collected from the certified CEM system.

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

11. Nitrogen Oxides (NOx)

a. *Initial Test*: NOx emissions shall not exceed 2.5 ppmvd corrected to 15% oxygen when operating on natural gas and 10 ppmvd corrected to 15% oxygen when operating on distillate fuel oil when operating in the combined cycle mode nor 9 ppmvd corrected to 15% oxygen when operating on natural gas and 36 ppmvd corrected to 15% oxygen when operating on distillate fuel oil when operating in the simple cycle mode based on a 3-hour test average as determined by EPA Method 7E.

b. *Continuous Compliance*: NOx emissions shall not exceed 2.5 ppmvd corrected to 15% oxygen when operating on natural gas and 10 ppmvd corrected to 15% oxygen when operating on distillate fuel oil when operating in the combined cycle mode nor 9 ppmvd corrected to 15% oxygen when operating on natural gas and 36 ppmvd corrected to 15% oxygen when operating on distillate fuel oil when operating in the simple cycle mode based on a 3-hour block average as determined by valid data collected from the certified CEM system.

NOx emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

12. Particulate Matter (PM/PM_{10}): The fuel specifications established in Condition No. 7 of this section combined with the efficient combustion design and operation of the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Particulate matter emissions shall not exceed 10 pounds per hour as determined by EPA Method 5, front-half catch only. [Rule 62-212.400(BACT), F.A.C.]

13. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2): The fuel sulfur specification established in Condition No. 7 of this section effectively limits the potential emissions of SAM and SO_2 from the combined cycle gas turbine. Compliance with the fuel sulfur specification shall be demonstrated by the sampling, analysis, record keeping and reporting requirements established in Section III.C of this permit. [Rule 62-212.400(BACT), F.A.C.]

14. Visible Emissions: As determined by EPA Method 9, visible emissions shall not exceed 10% opacity based on a 6-minute average. Except as allowed by Condition No. 16 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

15. Volatile Organic Compounds (VOC): The efficient combustion of clean fuels and good operating practices for the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the fuel specification and CO standards shall serve as indicators of good combustion. VOC emissions shall not exceed 1.4 ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Rule 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

16. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for during specifically defined periods of startup, shutdown, and malfunction of the

combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.

b. *Low Load Restriction*: Except for startup and shutdown, operation below 50% base load is prohibited.

c. *CEM System Data Exclusion*: Except for combined cycle cold startups, no more than two hourly average emission rate values shall be excluded from the continuous NOx compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than four hourly average emission rate values shall be excluded from the continuous NOx compliance demonstrations due to combined cycle cold startups. No more than a total of four hourly average emission rate values shall be excluded from the continuous NOx compliance demonstrations for all such episodes in any calendar day. A "combined cycle cold startup" is defined as startup after the combined cycle gas turbine has been shutdown for 48 hours or more. A "documented unavoidable malfunction" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

[Design; Rules 62-4.070(3), 62-4.130, 62-210.700, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{Permitting Note: Performance test methods are specified in Gas Turbine Common Conditions, Section III.C.}

17. Initial Compliance Tests: The combined cycle gas turbine shall be tested to demonstrate compliance with the emission standards for CO, NOx, visible emissions and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. With appropriate flow measurements, certified CEM system data may be used to demonstrate compliance with the CO and NOx standards. NOx emissions recorded by the CEM system shall be reported for each ammonia slip test run. [Rule 62-297.310(7)(a)1., F.A.C.]

18. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the combined cycle gas turbine shall be tested to demonstrate compliance with the emission standards for ammonia slip and visible emissions. NOx emissions recorded by the CEM system shall be reported for each ammonia slip test run. {Permitting Note: Continuous compliance with the CO and NOx standards is demonstrated with certified CEMS system data.} [Rules 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

19. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. The CEM systems shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C. The CO monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. The NOx monitor shall have a span of no more than 10 ppmvd corrected to 15% oxygen. For purposes of determining compliance with the CEM emission standards of this permit, missing or excluded data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour average. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to

demonstrate continuous compliance with the corresponding CO and NOx emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

20. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to 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. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

OTHER REQUIREMENTS

Each combined cycle gas turbine is also subject to the "Gas Turbine Common Conditions" specified in Section III.C as well as the "Standard Conditions" included as Appendix SC in Section IV.

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

Emissions Units 001 and 002: Simple Cycle Unit Nos. 1 and 2
Description: Each simple cycle unit consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW. Ancillary equipment includes an automated gas turbine control system, and an inlet air filtration system. The Combined Cycle Unit 3 gas turbine can also operate in the simple cycle mode. **Fuel:** The simple cycle units are fired with pipeline-quality natural gas as the primary fuel, with No. 2 fuel oil as the standby fuel. **Capacity:** At a compressor inlet air temperature of 35° F, the combined cycle gas turbine produces 174 MW when firing approximately 1,614 MMBtu (LHV) per hour of natural gas and 183 MW when firing approximately 1,790 MMBtu (LHV) per hour of distillate fuel oil. **Controls**: Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of pipeline-quality natural gas at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology. **Stack Parameters**: When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit a 100 feet tall stack that is 21 feet in diameter with a flow rate of approximately 2,406,300 acfm at 1117° F.

APPLICABLE STANDARDS AND REGULATIONS

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

EQUIPMENT

2. Simple Cycle Gas Turbines: The permittee is authorized to install, tune, maintain and operate two new General Electric Frame 7FA gas turbine-electrical generator sets. Each simple cycle unit shall be designed and operated to generate a nominal 174 MW of shaft-driven electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, a single exhaust stack that is 100 feet tall and 21 feet in diameter, and associated support equipment. [Applicant Request; Design]

3. DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric dry low-NOx combustion system to control NOx emissions from each simple cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the dry low-NOx combustors and automated gas turbine control system shall be tuned to minimize NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Simple Cycle Operation Only: Each gas turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated

temperatures of the exhaust gas as well as costs related to restricted operation. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

5. Permitted Capacity: The maximum heat input rate to each simple cycle gas turbine shall not exceed 1,614 mmBTU per hour while producing approximately 174 MW at ISO conditions, the lower heating value (LHV) of natural gas, and 100% load; or 1,790 mmBTU per hour while producing approximately 183 MW at ISO conditions, the lower heating value (LHV) of No. 2 fuel oil, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, 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. [Design; Rule 62-210.200(PTE), F.A.C.]

6. Fuel Specifications: Each simple cycle gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.05% by weight. Oil firing shall not exceed 500 hours per year. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

7. Restricted Operation: Each simple cycle gas turbine shall operate no more than 3,390 hours per year on natural gas and 500 hours per year on natural gas. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to each simple cycle gas turbine. Unless otherwise noted, the mass emission limits are based a compressor inlet temperature of 35° F and 100% load. For comparison to the standard, actual measured mass emissions shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

8. Carbon Monoxide (CO): CO emissions from each simple cycle gas turbine shall not exceed 7.4 ppmvd corrected to 15% oxygen when operating on natural gas nor 20 ppmvd corrected to 15% oxygen when operating on distillate fuel oil based on a 3-hour test average as determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]

9. Nitrogen Oxides (NOx)

   a. *Initial Performance Test*: NOx emissions from each simple cycle gas turbine shall not exceed 9 ppmvd corrected to 15% oxygen when operating on natural gas nor 36 ppmvd corrected to 15% oxygen when operating on distillate fuel oil based on a 3-hour test average conducted at base load as determined by EPA Method 7E.

   b. *CEM System*: NOx emissions shall not exceed 9 ppmvd corrected to 15% oxygen when operating on natural gas nor 36 ppmvd corrected to 15% oxygen when operating on distillate fuel oil based on a 24-hour block average as determined by valid data collected from the certified NOx CEM system.

   NOx emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

10. Particulate Matter (PM/PM_{10}): The fuel specifications established in Condition No. 6 of this section combined with the efficient combustion design and operation of the simple cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Particulate matter emissions shall not exceed 10 pounds per hour as determined by EPA Method 5, front-half catch only. [Rule 62-212.400(BACT), F.A.C.]

11. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2): The fuel sulfur specification established in Condition No. 7 of this section effectively limits the potential emissions of SAM and SO_2 from each simple cycle gas turbine. Compliance with the fuel sulfur specification shall be demonstrated by the sampling, analysis, record keeping and reporting requirements established in Section III.C of this permit. [Rule 62-212.400(BACT), F.A.C.]

12. Volatile Organic Compounds (VOC): The efficient combustion of clean fuels and good operating practices for the simple cycle gas turbines represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the fuel specification and CO standards shall serve as indicators of good combustion. VOC emissions shall not exceed 1.4 ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Rule 62-212.400(BACT), F.A.C.]

13. Visible Emissions: As determined by EPA Method 9, visible emissions shall not exceed 10% opacity based on a 6-minute average. Except as allowed by Condition No. 14. of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

14. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for during specifically defined periods of startup, shutdown, and malfunction of each simple cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

    a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.

    b. *Low Load Operation*: Except for startup and shutdown, operation below 50% base load is prohibited.

    c. *CEM System NOx Data Exclusion*: No more than two hourly average emission rate values shall be excluded from the continuous NOx compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than a total of three hourly average emission rate values shall be excluded from the continuous NOx compliance demonstrations for such periods in any calendar day. A "documented unavoidable malfunction" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

    [Design; Rules 62-210.700, 62-4.130, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{Permitting Note: Performance test methods are specified in Gas Turbine Common Conditions, Section III.C.}

15. Initial Tests Required: Each simple cycle gas turbine shall be tested initially to demonstrate compliance with the emission standards for PM, CO, NOx, VOC and visible emissions. The initial tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later

than 180 days after initial operation of each unit. With appropriate flow measurements, certified CEM system data may be used to demonstrate compliance with the NOx standards. Tests for CO and VOC emissions shall be conducted concurrently. [Rule 62-297.310(7)(a)1., F.A.C.]

16. Annual Performance Tests: During each federal fiscal year (October 1st to September 30th), each simple cycle gas turbine shall be tested to demonstrate compliance with the emission standards for CO and visible emissions. NOx emissions recorded by the CEM system shall be reported for each CO test run. {Permitting Note: Continuous compliance with the NOx standard is demonstrated with certified CEMS system data.} [Rule 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

17. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record NOx emissions from each simple cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. Each CEM system shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C. Each NOx monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. Compliance with the continuous NOx emissions standards shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average 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 CEM emission standards of this permit, missing (or excluded) data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding NOx emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

OTHER REQUIREMENTS

Each simple cycle gas turbine is also subject to the "Gas Turbine Common Conditions" specified in Section III.C as well as the "Standard Conditions" included as Appendix SC in Section IV.

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

ID	EMISSION UNIT DESCRIPTION
001	**Simple Cycle Unit 1** consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW.
002	**Simple Cycle Unit 2** consists of a General Electric Frame 7FA gas turbine-electrical generator set with a nominal capacity of 174 MW.
003	**Combined Cycle Unit No. 3** consists of a natural gas fired 174 MW gas turbine-electrical generator set, an unfired heat recovery steam generator, and a steam turbine-electrical generator with a capacity of less than 75 MW. The turbine can also operate in the simple cycle mode.

NEW SOURCE PERFORMANCE STANDARDS, SUBPART GG

1. NSPS Requirements: The Department determines that compliance with the emissions performance and monitoring requirements of Sections III.A and B also demonstrates compliance with the New Source Performance Standards for gas turbines in 40 CFR 60, Subpart GG. For completeness, the applicable Subpart GG requirements are included in Appendix GG of this permit. [Rule 62-4.070(3), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combined cycle gas turbine 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.]

EXCESS EMISSIONS

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

EMISSIONS PERFORMANCE TESTING

4. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
5	Determination of Particulate Matter Emissions from Stationary Sources {Note: For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

Test Methods, Continued

Method	Description of Method and Comments
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

CONTINUOUS MONITORING REQUIREMENTS

5. CEM Systems: Each continuous emissions monitoring (CEM) system shall comply with the following requirements:

   a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported quarterly to each Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of 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.

   b. *NOx Monitors.* Each NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 7E, of Appendix A of 40 CFR 60.

   c. *O_2 or CO_2 Monitors.* The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and/or NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel fired. Each O_2 and CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported quarterly to each Compliance Authority. The RATA tests required for the O_2 or CO_2 monitors shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *Data Collection.* Each hourly 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). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. The CEM system shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen. The CEM system shall be used to demonstrate compliance with the CEM emission standards for CO and NOx as specified in this permit. Upon request by the Department, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *Data Exclusion.* All required emissions data shall be recorded by the CEM systems during episodes of startup, shutdown and malfunction. CO and NOx emissions data recorded during such episodes may be excluded from the corresponding compliance-averaging period subject to the conditions specified in Sections III.A and B of this permit. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction 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 episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Data Exclusion Reports.* A summary report of the duration of data excluded from each compliance average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined to include the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall include the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than quarterly, including periods in which no data is excluded or no instances of missing data occur.

g. *Notification*: If a CEM system reports CO or NOx emissions in excess of an emissions standard, the permittee shall notify each Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

h. *Availability.* Monitor availability for CO and NOx CEM systems shall be 95% or greater in any calendar quarter. The report required in Appendix XS of this permit shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

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

RECORDS

6. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

7. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of fuel consumption for each gas turbine in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

8. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption (million cubic feet of natural gas per month), heat input rates (million BTU per month), and hours of operation for each gas turbine. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

REPORTS

9. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, emissions shall be reported as "excess emissions" when emission levels exceed the standards specified in this permit (including periods of startup, shutdown and malfunction). Within 30 days following each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions, periods of data exclusion, and CEMS systems monitor availability for the previous calendar quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

D. AUXILIARY BOILER

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

Emissions Units 004: Auxiliary Boiler
Description: The auxiliary boiler consists of an 84 MMBtu/hr, natural gas fired Nebraska Boiler Company boiler. **Fuel:** The auxiliary boiler is fired exclusively with pipeline-quality natural gas. **Capacity:** The capacity of the auxiliary boiler is 84 mmBTU per hour of natural gas. **Controls**: Emissions of CO and VOC are minimized by the efficient combustion of pipeline-quality natural gas at high temperatures. NOx emissions are reduced by a low-NOx burner. **Stack Parameters**: Exhaust gases exit a 85 feet tall stack that is 2.35 feet in diameter with a flow rate of approximately 27,160 acfm at 300° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions standards specified for this unit represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. The emissions unit is also subject to the requirements of 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. [Rule 62-212.400(BACT), F.A.C.]

EQUIPMENT

2. Auxiliary Boiler: The permittee is authorized to install, maintain and operate one new 84 MMBtu/hr, natural gas fired Nebraska Boiler Company boiler. Ancillary equipment includes a single exhaust stack that is 85 feet tall and 2.35 feet in diameter, and associated support equipment. [Applicant Request; Design]

PERFORMANCE REQUIREMENTS

3. Permitted Capacity: The maximum heat input rate to the auxiliary boiler shall not exceed 84 mmBTU per hour lower heating value (LHV) of natural gas. [Design; Rule 62-210.200(PTE), F.A.C.]

4. Fuel Specifications: Each simple cycle gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

5. Restricted Operation: The hours of operation for the auxiliary boiler are not limited (8760 hours per year). [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: Appendix BD provides a summary of the emissions standards of this permit.}

6. Carbon Monoxide (CO): CO emissions from the auxiliary boiler shall not exceed 16.8 pounds per hour based on a 3-hour test average as determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]

7. Nitrogen Oxides (NOx): NOx emissions from the auxiliary boiler shall not exceed 8.4 pounds per hour based on a 3-hour test average as determined by EPA Method 20. NOx emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

8. Volatile Organic Compounds (VOC): VOC emissions shall not exceed 3.5 pounds per hour as determined by EPA Method 25A measured and reported as methane. [Rule 62-212.400(BACT), F.A.C.]

9. Visible Emissions: Visible Emissions shall not exceed 20 percent opacity as determined by EPA Method 9 based on a 6-minute average. [Rule 62-2296.320, F.A.C.]

EXCESS EMISSIONS

10. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for during specifically defined periods of startup, shutdown, and malfunction of each auxiliary boiler. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes. [Design; Rules 62-210.700, 62-4.130, 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 emissions shall be included in any compliance demonstration based on continuous monitoring data. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{Permitting Note: Performance test methods are specified in Emission Standards Conditions, Section III.D.}

12. Initial Tests Required: Each auxiliary boiler shall be tested initially to demonstrate compliance with the emission standards for CO, NOx, VOC and visible emissions. The initial tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each unit. Tests for CO and VOC emissions shall be conducted concurrently. [Rule 62-297.310(7)(a)1., F.A.C.]

REPORTING AND RECORDKEEPING REQUIREMENTS

13. Notification Required: The owner or operator shall submit notification of the date construction or reconstruction, anticipated startup, and actual startup, as provided by 40 CFR60.7. This notification shall include:

    a. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

    b. The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired. [40CFR60.48c(a)]

14. Recordkeeping: The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. [40CFR60.48c(g)]

E. FUEL STORAGE TANK

This permit authorizes installation of the following emissions unit.

ID	Emission Unit Description
005	**2.8 Million Gallon Fuel Oil Storage Tank.**

APPLICABLE STANDARDS AND REGULATIONS

1. Applicable Regulations: The emissions unit is subject to the applicable standards contained in 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. [40CFR60.110b]

EQUIPMENT

2. Fuel Storage Tank: The permittee is authorized to install, maintain and operate one new 2.8 million gallon fuel storage tank. [Applicant Request; Design]

REPORTING AND RECORDKEEPING REQUIREMENTS

3. Recordkeeping: The owner or operator of each storage vessel shall keep readily accessible records showing the dimensions of the storage vessel and an analysis showing the capacity of the storage vessel. Each storage These records will be kept for the life of the source. [40CFR60.116b(a)]

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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

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

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

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

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

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

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

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

NSPS SUBPART GG REQUIREMENTS

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

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

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

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

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

where:

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

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

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

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

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

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

Department requirement: **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" value for this unit is approximately 10 for natural gas. The equivalent emission standard is 108 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

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

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

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

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

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

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

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

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

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

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

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

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

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

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

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

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

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

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

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

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

where:

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

Department requirement: The owner or operator is not required to have the 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.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

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

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

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

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

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

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

CONTINUOUS MONITOR SYSTEMS SEMI-ANNUAL REPORT

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

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

Reporting period dates: From ______________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ____

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

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

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

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

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

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

____
Name

____
Title

____ ______________________
Signature *Date*

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Richard L. Wolfinger
Vice President
South Pond Energy Park, LLC
111 Market Place
Suite 200
Baltimore, Maryland 21202

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 10/11/00

C. Signature

X Diane Young

☐ Agent ☐ Addressee

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

3. Service Type

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

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

2. Article Number *(Copy from service label)*

7000 0520 0020 9371 1649

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

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

7000 0520 0020 9371 1649

Mr. Richard L. Wolfinger

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