Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 1, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Project No. 1110100-001-AC
Draft Air Permit No. PSD-FL-302
Duke Energy Fort Pierce, LLC
Proposed New 640 MW Gas Turbine Peaking Plant

Dear Mr. Gilliland:

Enclosed is one copy of the Draft Permit to construct a new 640 MW electrical generating plant located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

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

CHF/AAl/jfk

Enclosures

In the Matter of an
Application for Air Permit by:

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Draft Permit No. PSD-FL-302
Emission Units 001 – 009
St. Lucie County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, Duke Energy North America, applied on October 5, 2000 to the Department for an air construction permit to construct a new 640 MW electrical generating plant located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The Draft Permit authorizes the construction of eight General Electric Model PG7121(EA) combustion turbine-electrical generator sets, each having a nominal generating capacity of 80 MW.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

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

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S. however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

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

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

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

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. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/1/01 to the person(s) listed:

Mr. Steven F. Gilliland, Duke Energy*
Mr. Nathan K. Plagens, Duke Energy
Mr. George Howroyd, CH2MHILL
Chair, St. Lucie Board of County Commissioners
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

Charlotte J. Hayes (Clerk) 5/1/01 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 1110100-001-AC
Draft Permit PSD-FL-302

Duke Energy Fort Pierce, LLC
Proposed 640 MW Simple Cycle Gas Turbine Plant
Emissions Units 001 - 009

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Duke Energy Fort Pierce, LLC to construct a nominal 640 MW simple cycle gas turbine plant. The proposed plant will be located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The applicant plans to install eight new simple cycle gas turbine-electrical generator sets with inlet air fogging systems and necessary support equipment. Each unit is a General Electric Model PG7121(EA) gas turbine with a nominal generating capacity of 80 MW. The applicant's authorized representative is Mr. Steven F. Gilliland, Senior Vice President of Duke Energy North America. The applicant's mailing address is 5400 Westheimer Court, Houston, TX 77056-5310.

Each simple cycle gas turbine will be fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Operation is restricted to an average of 2500 hours per gas turbine per year with no more than 500 hours of oil firing per gas turbine per year. When firing natural gas, nitrogen oxide emissions will be minimized with dry low-NOx combustion technology. When firing very low sulfur distillate oil, nitrogen oxide emissions will be minimized with wet injection and restricted operation. Emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of these clean fuels.

The potential emissions from this project are shown in the following table.

Pollutant	Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	540	100	Yes	Yes
NOx	632	40	Yes	Yes
PM/PM_{10}	60	25/15	Yes	Yes
SAM	17	7	Yes	Yes
SO_2	147	40	Yes	Yes
VOC	29	40	No	No

As indicated, a determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM) and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. An air quality impact analysis was conducted by the applicant and reviewed by the Department. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

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

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

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

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:

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

Florida Department of Environmental Protection
Southeast District Office – Air Resources
(400 North Congress Avenue)
P.O. Box 15425
West Palm Beach, Florida 33401
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION
(Including Draft BACT Determinations)

Duke Energy Fort Pierce, LLC

New 640 MW Simple Cycle Gas Turbine Peaking Plant

St. Lucie County

Project No. 1110100-001-AC
Draft Permit No. PSD-FL-302

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

April 25, 2001

{Filename: 302 BACT and TEPD.DOC}

This document describes the overall project, rule applicability, draft determination of Best Available Control Technology, analysis of air quality impacts, and makes a preliminary determination. It is organized in the following sections:

Section	Page	Description
1	1	General Project Information
2	2	Applicable Regulations
3	4	Draft BACT Determinations
4.	14	Air Quality Analysis
18	18	Preliminary Determination

1. GENERAL PROJECT INFORMATION

1.1 Applicant Name and Address

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Authorized Representative:
Mr. Steven F. Gilliland, Senior Vice President

1.2 Processing Schedule

10/05/00	Department received the application for a PSD air pollution construction permit.
10/11/00	Department mailed copies to EPA Region 4 and the National Park Service.
10/26/00	Department requested additional information.
12/14/01	Department received additional information.
01/08/01	Department requested additional information
02/27/01	Department received additional information; application complete.

1.3 Facility Description and Location

The applicant proposes to construct a new 640 MW electrical generating plant consisting of eight 80 MW simple cycle gas turbines. The planned project will be located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. This is an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The UTM coordinates are Zone 17, 561.6 km East, and 3029.0 km North. This location is approximately 190 km from the nearest Class I area, the Everglades National Park.

1.4 Standard Industrial Classification Code (SIC)

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

Industry No. 4911, Electric Services

1.5 Regulatory Categories

Title III: Based on available data, the new facility is not 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: The new facility is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: Emissions of at least one regulated pollutant from the new facility will be greater than 250 tons per year. The project is located in an area designated as in attainment or unclassifiable for each pollutant subject to a National Ambient Air Quality Standard. Therefore, the project is subject to new source preconstruction review in accordance with Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: New units are subject to the New Source Performance Standards of 40 CFR 60 include the gas turbines (Subpart GG) and the fuel storage tanks (Subpart Kb).

1.6 Project Description

The applicant proposes construction of a new 640 MW electrical generating plant in St. Lucie County comprised of eight simple cycle gas turbines. Each gas turbine consists of a General Electric Model PG7121(EA) gas turbine-electrical generator, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 93 feet tall and 15 feet in diameter. Each unit is designed to produce a nominal 80 MW of electrical power. The applicant proposes to limit operation of each gas turbine to an average of no more than 2500 hours per year. To control nitrogen oxide emissions, the applicant proposes dry low-NOx (DLN) combustion technology when firing natural gas and wet injection with restricted operation when firing low sulfur distillate oil as a backup fuel.

1.7 Potential Emissions

Table 1A. This table summarizes potential project emissions and the resulting PSD applicability.

Pollutant	PTE As Proposed [a] (Tons Per Year)	PTE Draft Permit [b] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	520	540/432	100	Yes	Yes
Lead	Negligible	Negligible	0.60	No	No
NOx	646	632	40	Yes	Yes
PM/PM_{10}	138	60	25/15	Yes	Yes
SAM	17	17	7	Yes	Yes
SO_2	148	147	40	Yes	Yes
VOC	20	29	40	No	No

[a] The applicant's potential emissions were based on eight gas turbines, each with 2000 hours per year of gas firing and 500 hours per year of oil firing. Operation was assumed to be 100% load with a compressor inlet temperature of approximately 75° F.

[b] The Department's potential emissions were based on eight gas turbines, each with 2000 hours per year of gas firing and 500 hours per year of oil firing. In addition to the permit limits, operation was assumed to be 100% load with a compressor inlet temperature of approximately 59° F. CO emissions assumed to be 25 ppmvd for first year and then 20 ppmvd thereafter. Also, the "back half condensables" were not included for PM/PM_{10} emissions. VOC emissions were assumed to be 2 ppmvd to remain "minor" with respect to PSD applicability.

2. APPLICABLE REGULATIONS

2.1 State Regulations

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

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

2.2 Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the following sections of the Code of Federal Regulations (CFR).

Title 40, CFR	Description
Section 51.166	Requirements for State Implementation Plans, Prevention of Significant Deterioration
Section 52.21	Approval of State Implementation Plans, Prevention of Significant Deterioration
Part 60	Subpart A - General Provisions for NSPS Sources
	NSPS Subpart GG - Stationary Gas Turbines
	NSPS Subpart Kb - Fuel Storage Tanks
	Applicable Appendices
Part 72	Acid Rain Permits
Part 73	Allowances
Part 75	Monitoring
Part 77	Acid Rain Program - Excess Emissions

2.3 General PSD Applicability

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required only in areas currently in attainment with the National Ambient Air Quality Standard (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it emits or has the potential to emit:

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

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

2.4 PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to predict ambient impacts from the project; a comparison of predicted ambient impacts from the project with National Ambient Air Quality Standards and PSD Increments; an evaluation of the air quality impacts from the project upon soils, vegetation, wildlife, and visibility; and an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The purpose of the Air Quality Analysis is to determine whether or not the proposed project will have a significant impact on Class I and Class II Areas and determine whether or not emissions from the project contribute significantly to, or cause a violation of, any state or federal ambient air quality standards.

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

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

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

BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

2.5 PSD Applicability for Project

The proposed new plant will be located in St. Lucie County, Florida, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). As shown in Table 1A, the new plant is considered a PSD-major source because potential emissions of at least one regulated pollutant exceed 250 tons per year. Emissions of CO, NOx, PM/PM_{10}, SAM and SO_2 are significant and the Department is required to make determinations of the Best Available Control Technology (BACT) for these pollutants and review the applicant's air quality impact analysis.

3. DRAFT BACT DETERMINATIONS

3.1 Available Information

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

- Informal comments received from the National Park Service;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical documents regarding DLN emissions and the gas turbine control system;
- Equipment costs for an oxidation catalyst (CO) and "hot" selective catalytic reduction system (NOx);
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation; Prepared for the U.S. Department of Energy (November 5, 1999);

- Proposed AP-42 changes to Section 3.1 for gas turbines (April 2000);
- Recently issued Department permits for the General Electric Model PG7121(EA) gas turbine;
- CO/NOx performance curves for the General Electric Model PG7121(EA) gas turbine;
- Emissions test data for a new GE Model PG7121(EA) gas turbine (Hardee Power Station Unit 2B);
- Goal Line Environmental Technology Website: http://www.glet.com; and
- Catalytica Website – www.catalytica-inc.com

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. A list of recent determinations regarding similar projects in the United States is provided in the following table.

Table 3A. Summary of Recent CO and NOx BACT Standards
80 MW Simple Cycle Gas Turbines (Gas Firing)

Project Location	Nominal Unit MW	Date	Controls	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	Operation hr/yr	Oil hr/yr
PSEG Fossil LLC Linden (NJ)	80	02/00	GE DLN	NA	12	NA	(authorized)
Hardee Power Partners (FL)	80	10/99	GE DLN	25, 1st year 20, after 1st year	9, 24-hr (CEMS)	8760	876
FPC Intercession City (FL)	80	12/99	GE DLN	25, 1st year 20, after 1st year	9, initial test 10, 3-hr (CEMS)	3390	833
Georgia Power Jackson Co. (GA)	80	08/99	GE DLN	45	12	4000	1000
Duke Energy Marshall Co. (KY)	80	Draft	GE DLN	20	12, 1-hr 9	2500	500
TVA Johnsonville Fossil Plant (TN)	80	07/99	GE DLN	25	15	2628	876
TVA Gallatin Fossil Plant (TN)	80	07/99	GE DLN	25	15	2628	876
Enron, Des Plaines Greenland (IL)	80	09/99	GE DLN	25	12, monthly 15, 1-hr	3250	0
Enron Kendall New Century (IL)	80	01/00	GE DLN	25	12, monthly 15, 1-hr	3300	0
Duke Energy (IL)	80	Draft	GE DLN	NA	12, annual 15, 1-hr	2000	500
Vermillion Generating Station (IN)	80	07/99	GE DLN	25	12, annual 15, 1-hr	2500	NA
Duke Energy Madison (OH)	80	07/99	GE DLN	25	12, annual 15, 1-hr	2500	500
Wisconsin Public Service (WI)	80	07/99	GE DLN	25	9, 24-hr	4000	2000
Wisconsin Electric (WI)	80	Draft	GE DLN	25	9, 24-hr	2000	NA

Table Notes:

- All data presented is for the General Electric Model 7EA gas turbine firing natural gas. The above information includes only units with a draft or final permit.
- "GE DLN" means General Electric's dry low-NOx combustion technology.

- "CEMS" means continuous emissions monitoring system. These projects should all be subject to Title IV, which requires a NOx CEMS.
- Some units have other modes of operation such as steam injection for power augmentation or high temperature peaking, which is not listed in the above table.

3.2 Nitrogen Oxides (NOx)

Discussion of Emissions

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures associated with combustion turbines, the primary pollutant of concern is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd corrected to 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions in the range of 150 ppmvd corrected to 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from gas turbines is 75 ppmvd corrected to 15% oxygen and ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures due to the inherently lower thermal NOx portion. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Many new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure, which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to 100% of base load. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, usually less than 32° F.

Description of Available Controls

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

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850° F. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd) with control efficiencies up to 98%. This control alternative is not feasible for simple cycle projects because the gas turbine exhaust temperature (1100° F) is above the design temperature range for this technology.

"Hot" Selective Catalytic Reduction (SCR): Due to temperature limitations of conventional SCR catalysts, vendors have developed specially formulated catalysts designed to further the reduction reaction at temperatures up to 1100° F. Also, cooling air can be added to reduce the gas temperatures to the appropriate design range. Hot SCR can deliver NOx control efficiencies of 70% to 95%.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For boilers, SNCR has achieved control efficiencies in the 40% to 60% range. This control alternative is not feasible for simple cycle projects because the gas turbine exhaust temperature (1100°F) is below the design limit (1600° F) for this technology.

Non-Selective Catalytic Reduction (NSCR): NSCR uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor in exhaust gas streams containing less than 3% oxygen. This technology has only been applied to automobiles and stationary reciprocating engines with variable control efficiencies. This control alternative is not feasible for simple cycle projects because the oxygen content of the combustion turbine exhaust (13% to 15%) is above the design level for this technology.

SCONOx™: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and distributed by ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which requires a heat recovery steam generator for use with a combined cycle gas turbine. SCONOx™ can achieve control efficiencies in the 90% to 98% range. This control alternative is not feasible for simple cycle projects because the gas turbine exhaust temperature of 1100°F is above the design limit for this technology.

XONON™: This is an emerging technology that partially burns fuel in a low-temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature (and less NOx formation) followed by flame-less catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but will be specific to each manufacturer and model of gas turbine. It is anticipated that control efficiencies will be in the 80% to 95% range. This emerging technology is model-specific and not yet commercially available for the General Electric Model PG7121(EA).

Cannon Technology's Low Temperature Oxidation (LTO): This technology involves injecting ozone into a gas stream (approximately 300° F) to oxidize CO, NOx, and SO_2 to carbonates, nitrates, and sulfates, which are then absorbed by a dilute nitric acid solution in a scrubber. The system was developed for steam boilers and test results show NOx emissions below 4 ppmvd at 3% oxygen for gas firing. However, only very small units (< 20 mmBTU per hour) have been tested. It is unknown as to whether this technology could be adapted to gas turbines exhausts. Therefore, LTO is not yet demonstrated or commercially available for gas turbines.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided funding to several gas turbine manufacturers to aid in the development of inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. For the 7EA Frame units, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The lean premix mode of operation occurs at 50% to 100% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for dry low-NOx combustor technology, the automated gas turbine control system becomes a critical component of the overall system. DLN systems result in control efficiencies of 80% to 95%. DLN technology research for oil firing continues. Dry low-NOx combustion technology is an integral component of the General Electric PG7121(EA) gas turbine.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies. Because dry low-NOx combustion technology does not yet achieve low NOx emissions when firing oil, wet injection remains a viable control technique for oil firing.

Applicant's Proposed NOx Controls

The applicant recognized "hot" selective catalytic reduction with dry low-NOx (DLN) combustion technology as the top control option followed by DLN combustion technology alone and wet injection. Although identified as potentially feasible, the applicant does not believe hot SCR has been successfully demonstrated for this size unit. The applicant also makes the following claims regarding additional adverse impacts of hot SCR.

Energy Impacts: Due to a pressure drop across the catalyst, hot SCR would result in a loss of 612,500 kWh per gas turbine.

Environmental Impacts: The applicant mentions that hot SCR could result in ammonia emissions either as unreacted ammonia "slipping" past the catalyst or as an accidental release. Also, additional fine particulate matter (PM_{10}) could be emitted as ammonium bisulfate and ammonium sulfate.

Economic Impacts: The applicant performed a revised cost analysis for the addition of hot SCR based on the firing natural gas for 2500 hours per year in each unit. The applicant's revised estimate indicated that installation of hot SCR (per gas turbine) would result in a capital investment of $4,141,000 and total annualized costs of $1,282,000 per year. The Department notes that the applicant did not necessarily agree with the Department's request for revised items in this estimate. Based on a reduction of approximately 36 tons of NOx per year with hot SCR for gas firing, the incremental cost effectiveness was estimated to be approximately $35,000 per ton of NOx removed.

Applicant's Proposal: Based on the estimated high capital and operating costs associated with this add on control system, the applicant rejected hot SCR and proposed the following NOx standards based on DLN combustion when firing natural gas as the primary and wet injection with restricted distillate oil firing as a backup fuel

Gas: 12.0 ppmvd @ 5% oxygen, short-term basis (or 10.5 ppmvd @ 15% oxygen, long-term basis)

Oil: 42.0 ppmvd @ 15% oxygen, short-term basis

Department's Draft NOx BACT Determination

The Department also recognizes hot selective catalytic reduction (hot SCR) combined with dry low-NOx (DLN) combustion technology as the top control option followed DLN technology alone and wet injection. However, the Department notes that General Electric is able to guarantee NOx emissions of 9 ppmvd corrected to 15% oxygen for base-loaded units firing natural gas with the DLN technology of the Model PG7121(EA). The Department has the following comments regarding the applicant's discussion of additional adverse impacts.

Energy Impacts: Installation of hot SCR would result in a small energy penalty of approximately 0.3% per inch of pressure drop across the catalyst bed.

Environmental Impacts: Hot SCR would result in some ammonia "slip" and perhaps small amounts of fine particulate matter (PM_{10}). However, a properly designed SCR system and the firing of very low sulfur fuels (such as natural gas as the primary fuel) can reduce emissions of both pollutants.

Economic Impacts: In general, the Department agrees that adding hot SCR to the General Electric Model PG7121(EA) is not cost effective. However, the Department does not endorse the applicant's estimate, but predicts the cost effectiveness of hot SCR for this project to be approximately $20,000 per ton of NOx removed, as limited to 2500 hours per year. Even assuming operation of 5000 hours per year, the cost effectiveness would be more than $10,000 per ton of NOx removed. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also recognizes that the analysis is significantly influenced by three critical constraints: the applicant's request for simple cycle operation only, the applicant's request for restricted operation (average of 2500 hours per year per gas turbine), and the inherently low emissions of the General Electric Model PG7121(EA) gas turbine. Should the applicant later request operation of these gas turbines as base load units, conversion to combined cycle operation, the substitution of another gas turbine model, or the firing of an alternative fuel, the NOx BACT determination must be reevaluated as if the project had never been constructed, pursuant to Rule 62-212.400(2)(g), F.A.C.

Draft NOx BACT Determination: At this time, the Department rejects hot SCR as not cost effective for this simple cycle project based on the restricted level of operation requested by the applicant. Therefore, the Department determines BACT for NOx emissions to be the dry low-NOx combustion technology when firing natural gas as primary fuel and wet injection with restricted hours when firing low sulfur distillate oil as a backup fuel. This determination is consistent with recent BACT determinations for simple cycle units made in Florida and other states. The Department establishes the following NOx standards as BACT for this project.

Gas: 9.0 ppmvd @ 15% oxygen, initial 3-hour test average at base load "new and clean"

10.5 ppmvd @ 15% oxygen, 3-hour rolling CEMS average

Oil: 42.0 ppmvd @ 15% oxygen, initial 3-hour test average and 3-hour rolling CEMS average

Also, distillate oil firing will be limited to no more than an average of 500 hours per year per installed gas turbine. Corresponding mass emission limits will also be established in the draft permit with compliance demonstrated by an initial performance test. In making this determination, the Department gave consideration to the applicant's request to fire natural gas as the primary fuel with restricted firing of very low sulfur distillate oil. Natural gas is a clean fuel containing little contaminants that takes full advantage of

DLN the combustion technology of the Model PG7121(EA) gas turbine. The 3-hour average was specified due to General Electric's guarantee and because peaking units typically operate only a portion of the day.

The draft BACT standards are much more stringent than the NSPS standard in Subpart GG in 40 CFR 60. The "new and clean" emissions standard ensures that the installed units are capable of achieving the manufacturer's guaranteed emission rate. Compliance with the "new and clean" BACT standard shall be demonstrated by conducting initial performance tests in accordance with EPA Method 7E or 20. The permittee shall install, calibrate, operate, and maintain a certified NOx continuous emissions monitor (CEMS) to demonstrate continuous compliance with the 3-hour rolling BACT limit. The draft permit also includes the following restrictions:

- Each gas turbine shall operate in simple cycle mode only;
- No gas turbine shall operate more than 5000 hours per year;
- Operation of all installed gas turbines shall not exceed an average of 2500 hours per gas turbine per year;
- No gas turbine shall fire low sulfur distillate oil for more than 1000 hours per year;
- The firing of low sulfur distillate oil for all installed gas turbines shall not exceed an average of 500 hours per gas turbine year;
- Except for startup and shutdown, each gas turbine shall not operate below 50% of base load.

3.3 Carbon Monoxide CO

Discussion

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion. In general, CO emissions are inversely proportional to NOx emissions from gas turbines. However, new advanced combustor designs have also been able to greatly reduce CO emissions concurrently with lower NOx emissions.

Applicant's Proposed CO Controls

The applicant identified two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and the inherently low CO emissions of General Electric's dry low-NOx combustion design. An oxidation catalyst consists of a noble metal catalyst section incorporated into the combustion turbine exhaust. The catalyst would promote oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than under normal conditions. The control efficiency is primarily a function of gas residence time and can exceed 90%. For this project, the exhaust gas temperature of 1000°F is in the proper design range. The applicant recognized an oxidation catalyst as the top control. However, the applicant asserts that an oxidation catalyst would result in the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty of approximately 0.2% per inch of pressure drop across the catalyst.

Environmental Impacts: The oxidation catalyst could generate additional PM_{10} and SAM emissions due to the oxidation of ammonia and sulfur in the exhaust gas. An oxidation catalyst would result only in minimal air quality improvements. Spent catalyst may require disposal as a hazardous waste.

Economic Impacts: The applicant's revised estimate indicates that installation of an oxidation catalyst (per gas turbine) would result in a capital investment of $2,419,775 with a total annualized cost of $902,925. It was assumed that the catalytic system could remove an additional 59 tons of CO per year (90% control efficiency). This results in an incremental cost effectiveness for the oxidation catalyst of approximately $15,000 per ton of CO removed. The Department notes that the applicant did not necessarily agree with the Department's request for revised items in this estimate.

Applicant's Proposal: The applicant rejected the oxidation catalyst as not cost effective and not producing any measurable reductions in air quality impacts. The applicant proposed the following CO standards based on the combustion design of the Model PG7121(EA).

Gas: 25.0 ppmvd @ 15% oxygen, first 12 months

20.0 ppmvd @ 15% oxygen, after first 12 months

Oil: 20.0 ppmvd @ 15% oxygen

Department's Draft CO BACT Determination

The Department also recognizes an oxidation catalyst as the top control for CO emissions. It is noted that the Department has issued permits for the Model PG7121(EA) with a CO emission standard of 20.0 ppmvd for both gas and oil firing. The Department has the following comments regarding the applicant's discussion of additional adverse impacts.

Energy Impacts: The Department agrees that installation of an oxidation catalyst would result in a small energy penalty.

Environmental Impacts: Any additional PM_{10} or SAM emissions would be minimized because of the exceptionally low sulfur content of natural gas as well as the proposed distillate oil. The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in making the BACT determination. The purpose of the PSD program is to prevent the significant deterioration of air quality *before* such problems develop. The Department also notes that an oxidation catalyst may reduce emissions of hazardous air pollutants, such as formaldehyde. Most catalyst manufacturers have a program to take back the spent catalyst for regeneration, recycling and disposal.

Economic Impacts: In general, the Department agrees that the addition of an oxidation catalyst would not be cost effective for a simple cycle gas turbine with restricted operation. The Department does not endorse the applicant's estimate, but predicts the cost effectiveness to be approximately $6000 per ton of CO removed for the project, as limited to 2500 hours per year. Even assuming an operation of 5000 hours per year, the cost effectiveness would be $3000 per ton of CO removed. The high costs are partially the result of substantial expenses related to additional equipment, installation, catalyst replacement, and energy consumption. However, similar to the discussion for NOx controls, the Department recognizes that the cost analysis has been significantly constrained for this project by the applicant's requested operational restrictions.

Draft CO BACT Determination: The Department rejects the addition of an oxidation catalyst as not cost effective for the project based on the restricted level of operation requested by the applicant. The efficient combustion design of the General Electric Model PG7121(EA) is determined to represent BACT for CO emissions from this project. Therefore, the Department establishes the following CO standard as BACT for this project.

Gas: 25.0 ppmvd @ 15% oxygen (first 12 months), 3-hour test average

20.0 ppmvd @ 15% oxygen (after first 12 months), 3-hour test average

Oil: 20.0 ppmvd @ 15% oxygen, 3-hour test average

Corresponding mass emission limits will also be established in the draft permit. Compliance with the BACT emissions standard shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 10 at base load. The draft permit will include the limiting conditions identified in the NOx BACT determination to ensure that BACT is reevaluated for CO and NOx if the applicant later requests a switch to based loaded units, conversion to combined cycle operation, or substitution of gas turbine models. The NOx BACT determination must be reevaluated as if the project had never been constructed, pursuant to Rule 62-212.400(2)(g), F.A.C.

Note: A slightly higher first-year emission rate is allowed to mitigate the applicant's concerns regarding high initial CO emissions for recent startup of similar units in Indiana. The determination is also consistent with two recent simple cycle projects in Florida featuring the General Electric Model 7EA units (Hardee Power Station and FPC Intercession City). General Electric estimates maximum CO emissions to be "25 ppmvd" at base load with an exhaust gas concentration of 13.86% by volume. This is equivalent to 21 ppmvd corrected to 15% oxygen. Test data for a 7EA unit at the Hardee Power Station operating at approximately 98% load indicated actual CO emissions of 8.5 ppmvd corrected to 15% oxygen while NOx emissions were approximately 6.5 ppmvd corrected to 15% oxygen. The Department believes that CO emission levels much lower than the manufacturer's guarantee are achievable once the units are properly installed and tuned.

3.4 Particulate Matter (PM/PM_{10}), Sulfuric Acid Mist (SAM), and Sulfur Dioxide (SO_2)

Discussion

Emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2) will result from the combustion of natural gas. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfuric acid mist and sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas contains little ash, sulfur, or other contaminants.

Applicant's Proposed Controls for PM/PM_{10}, SAM, and SO_2

The applicant indicates that post-control devices have never been applied to gas turbines because of the large volumetric flow rates, low particulate concentrations, low sulfur dioxide concentrations, and excessive back pressure that would be caused by such add-on devices. In addition, clean fuels are required to prevent damage to turbine blades and other high-precision turbine components.

Applicant's Proposal (Fuel Specifications)

Gas: Pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 SCF

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

Department's Draft PM/PM_{10}, SAM, and SO_2 BACT Determinations

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. However, particulate emissions are estimated to be much less than 0.01 grains per dscf of exhaust gas, which is approximately the level of controlled emissions from a baghouse. Similarly, there is acid gas scrubbing equipment available to further reduce SAM and SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas as the primary fuel with very low sulfur distillate oil as a backup fuel. The Department agrees that further control of particulate matter, sulfuric acid mist, and sulfur dioxide emissions with any of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case.

Draft PM/PM_{10}, SAM, and SO_2 BACT Determinations: The Department establishes the following fuel specifications and opacity standard as BACT for PM/PM_{10}, SAM, and SO_2.

Gas: Pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 SCF

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

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

Compliance with the fuel sulfur limits shall be demonstrated by maintaining the fuel quality records. Limiting the fuel sulfur content also effectively limits the potential emissions of SAM and SO_2, so that additional emissions standards are unnecessary. In conjunction with the fuel specifications, the above opacity standard is specified in lieu of an emission standard due to the difficulty of conducting an isokinetic performance test for particulate matter at very high volumetric flow rates with exhaust temperatures near 1000° F. In addition, the collected sample is expected to be within the level of detection of the method. Note: The maximum estimated emissions of particulate matter are 5/10 pounds per hour for gas/oil firing, as determined by EPA Method 5 (front-half catch only). This is approximately 7.5 tons per year per gas turbine.

3.5 PSD-Synthetic Minor Limits for Volatile Organic Compounds (VOC)

VOC emissions result from incomplete combustion when firing natural gas. Large combustion turbines offer high temperatures with efficient combustion resulting in low levels of volatile organic compounds. Based on the applicant's request, the Department establishes the following standards as PSD-synthetic minor limits for VOC.

Gas: 2.5 pounds per hour (2.0 ppmvd corrected to 15% oxygen) based on a 3-hour test average

Oil: 4.5 pounds per hour (3.5 ppmvd corrected to 15% oxygen) based on a 3-hour test average

The above standards apply during the initial performance tests conducted at base load, measured and reported in terms of methane, as determined by EPA Method 25A. Optionally, EPA Method 18 may also be conducted concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane. The efficient combustion design, use of clean fuels and good operating practices minimize VOC emissions from each gas turbine. Compliance with the fuel specifications and CO standards of this section shall serve as indicators of good combustion. The initial tests shall demonstrate compliance with the standards and validate the maximum emissions rates. Subsequent VOC emissions performance tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C.

Note: The emissions limit proposed by the applicant was 1.8 pounds per hour (1.4 ppmvd corrected to 15% oxygen). The draft limit is slightly higher because the detectable limit of the test method is approximately 1 ppm. The draft limit establishes potential VOC emissions at 29 tons per year, which is well below the significant emissions rate.

3.6 Excess Emissions

Based on the design of the gas turbines and Rules 62-210.700 and 62-4.130, F.A.C., the following conditions will be included in the permit to address periods of excess emissions.

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 the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard.

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

a. During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

b. Except for startup and shutdown, operation below 50% base load is prohibited.

c. Data for NOx emissions and oxygen (or CO_2) content shall be recorded by the CEM system during all episodes of startup, shutdown and malfunction. Individual hourly average NOx emission rate values recorded during such episodes may be excluded from the continuous NOx compliance determination. No more than three (3) hourly average emission rate values shall be excluded in any 24-hour block period due to gas turbine startup, shutdown, or documented unavoidable malfunction. 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.

4. Air Quality Impact Analysis

4.1 Summary

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NOx, SO_2, and SAM. PM_{10}, SO_2 and NOx 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, AAQS or de minimis monitoring levels for SAM; the BACT determination will limit maximum potential SAM emissions.

The applicant's initial PM/PM_{10}, CO, NOx, and SO_2 air quality impact analyses for this project predicted no significant impacts in the Class II area in the vicinity of the project. Therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required in the Class II area. The nearest PSD Class I area is the Everglades National Park (ENP) located about 180 km to the south and southwest. The applicant's PSD Class I air quality analysis showed no significant impacts due to the project. Therefore, a cumulative PSD Class I increment analysis was not required for these pollutants. Also, the maximum predicted impacts for all pollutants 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_2 in the surrounding Class II Area;
- A significant impact analysis for PM_{10}, SO_2, and NO_2 in the ENP;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Based on the 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 vs. 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.

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 Greater Than De Minimis?
PM_{10}	24-hour	1	10	No
NO_2	Annual	0.1	14	No
SO_2	24-hour	2	13	No
CO	8-hour	10	575	No

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) station at West Palm Beach, Florida (surface and upper air data). The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

PSD Class I Area

Since the PSD Class I ENP is approximately 180 to 284 km from the proposed facility at its closest and farthest points, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and two Air Quality Related Values (AQRVs), regional haze and deposition of sulfur and nitrogen compounds. 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 mechanisms.

CALPUFF was first run in screen mode using ISCST3 meteorological input data consisting of 5 years of surface and upper air data from West Palm Beach. The 5-year period of meteorological data was from 1986 to 1990. The base ISCST3 data was supplemented with precipitation, solar radiation, and relative humidity data from the same station. The supplemental meteorological data was obtained from the National Climatic Data Center (NCDC) Hourly United States Weather Observations (HUSWO) and Solar and Meteorological

Surface Observation Network (SAMSON) compact discs. Solar radiation data, which is needed for the CALPUFF chemical transformation algorithms, is not available from NCDC after 1990; therefore data from 1986 to 1990 were used to fulfill the 5-year modeling requirement for running CALPUFF in the screen mode.

4.4 Significant Impact Analysis

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and II Areas. If this modeling at worst-case load conditions shows significant impacts, additional modeling which 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 is exempted from doing any further modeling.

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 100-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced receptors at 100 meters apart starting at 100 meters and extending to 3,000 meters from the stacks. Beyond 3000 meters, a spacing of 250 meters was used out to 6,000 meters from the facility. From 6 to 12 kilometers, a spacing of 0.5 kilometers was used. Between 12 and 20 kilometers, a spacing of 1 kilometer was used. The modeling approach was based on the assumption that a refined receptor grid (minimum 100 meter spacing) would be used as necessary in order to determine maximum predicted concentrations in various areas of the initial grid.

For the Class I screening analysis two rings of receptors were centered on the Duke Energy facility at distances bracketing the ENP. These distances represent the nearest boundary of 180 kilometers and the farthest boundary of 284 kilometers with respect to the proposed project. Receptors were placed at one-degree intervals over a 360-degree arc along each ring. The tables below show the results of the significant impact modeling for the Class II and Class I areas.

Predicted Maximum Air Quality Impacts from the Project Compared to the PSD Class II Significant Impact Levels in the Vicinity of the Project

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Class II Significant Impact Levels (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	No
	24-hour	2	5	No
	3-hour	14	25	No
PM_{10}	Annual	0.1	1	No
	24-hour	1	5	No
CO	8-hour	10	500	No
	1-hour	50	2000	No
NO_2	Annual	0.1	1	No

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

Predicted Maximum Air Quality Impacts from Project Compared to the EPA Proposed PSD Class I Significant Impact Levels (ENP)

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Class I Significant Impact Levels (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	No
	24-hour	0.1	0.3	No
NO_2	Annual	0.005	0.1	No
SO_2	Annual	0.002	0.1	No
	24-hour	0.2	0.2	No
	3-hour	0.7	1	No

The results of the significant impact modeling for the ENP show that there are no significant impacts predicted due to PM_{10} and NO_2 emissions from this project; therefore, no further modeling was required in the Class I area for these pollutants. However, impacts equal to the proposed significant impact level for the 24-hour averaging time were predicted. These significant impact levels are only proposed guideline values at this time; the Federal Land Manager (FLM) may make the determination that no adverse impact on the increments is expected and exempt the project from further PSD multi-source increment modeling. Based on the fairly large distance of the project from the ENP and the relatively low SO_2 emissions expected from it, the FLM determined that no further modeling was necessary. In addition, Duke Energy is limiting fuel oil firing to a maximum of 12 hours in any 24-hour period.

4.5 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas and oil-fired combustion turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. An analysis of sulfur and nitrogen deposition impacts in the ENP was done. Based on FLM criteria, no adverse impacts were predicted. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NOx, and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS. The project impacts are less than the significant impact levels, 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.

Impact On Visibility and Regional Haze

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NOx and SO_2 emissions will also minimize plume opacity. The contribution to smog in the area will be minimal. A regional haze analysis for the ENP was submitted by the applicant. Based on FLM criteria, no adverse impacts were predicted.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area. The proposed project has a small overall physical "footprint" and among the lowest air emissions per unit of electric power generating capacity for peaking operation.

Hazardous Air Pollutants

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

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for the project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.