Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

March 1, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Randall R. LaBauve, Vice President
Florida Power & Light Company (FPL)
West County Power Plant
700 Universe Boulevard
Juno Beach, Florida 33408

Re: FPL West County Energy Center
DEP File No. 0990646-001-AC (PSD-FL-354)
Two 1,250 MW Combined Cycle Units

Dear Mr. LaBauve:

Enclosed are documents indicating the Department's preliminary determination to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to FPL for the construction of two nominal 1,250 megawatt combined cycle units at the proposed West County Energy Center in Palm Beach County. The documents include: the "Intent to Issue PSD Permit;" the "Public Notice of Intent to Issue PSD Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. According to Paragraph 62-17.135(1)(c), F.A.C. the applicant shall have published the notice no later than 10 days (i.e. by March 11, 2006) after the preliminary determination has been issued.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 (meteorologist), Teresa Heron at 850/921-9521 (review engineer) or Mr. Linero at 850/921-9523 (P.E. Administrator).

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/aal/th

Enclosures

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

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Certified Fee	
Return Receipt Fee (Endorsement Required)	
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Postmark
Here

Mr. Randall R. LaBauve
Vice President
Environmental Services
Florida Power & Light
700 Universe Blvd.
Juno Beach, Florida 33408

PS Form 3800, May 2000 — See Reverse for Instructions

No Green Card

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0990646-001-AC (PSD-FL-354)

FPL West County Energy Center
Palm Beach County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) to the Florida Power & Light Company (FPL). The permit is one of several authorizations needed to construct two nominal 1,250 megawatts (MW) combined cycle units at the proposed FPL West County Energy Center at 4000 205th Street, North in unincorporated Palm Beach County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's corporate address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

The two proposed combined cycle units will each consist of: three nominal 250 MW combustion turbine-electrical generators; three supplementary-fired heat recovery steam generators (HRSGs); a single nominal 500 MW steam-electrical generator; a 24-cell mechanical draft cooling tower; and three exhaust stacks. Additional equipment not necessarily associated with a specific unit includes: two 6.3 million gallon diesel fuel storage tanks; two 99.7 MMBtu/hr auxiliary boilers; four 2250 KW emergency generators; and other associated support equipment.

Each combined cycle unit will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur (0.0015 percent sulfur) distillate fuel oil will be allowed as backup fuel for 500 hours per year per combustion turbine. Gas-fired duct burners located within the HRSGs will be used for limited periods of time to raise additional steam for use in the steam turbine-electrical generator.

Selective catalytic reduction (SCR) systems with ammonia injection will be used in conjunction with Dry Low-NO_X combustion (gas firing) and wet injection (oil firing) to control NO_X emissions. The Department's proposed BACT NO_X emission limit is 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2) of NO_X while firing natural gas. Sufficient catalyst will be used to minimize emissions of ammonia reagent. The Department's proposed NO_X limit while firing ultra low sulfur fuel oil is 8 ppmvd @15% O_2. The Department's proposed BACT CO emission limit is 8.0 ppmvd @15% O_2 on a 24-hour basis while burning gas, ultralow sulfur fuel oil, or using the duct burners. A CO limit of 6 ppmvd @15% O_2 applies on a 12-month rolling average. A BACT CO limit of 4.1 ppmvd @15% O_2 applies during initial and annual full load tests while burning natural gas without use of the duct burners.

Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emissions of CO and NO_X will be continuously monitored to demonstrate compliance with the conditions of the permit. BACT determinations for the ancillary equipment such as auxiliary boilers, fire pump engines, process heaters, cooling tower, and emergency generators are detailed in the Technical Evaluation and Preliminary determination. The complete set of proposed emission limits is available at the Department offices, the Palm Beach County Health Department, and the website address indicated below.

The applicant's initial estimates of maximum potential annual emissions from the project are summarized in the following table.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	968	100	Yes
Pb	0.050	0.6	No
NO_X	841	40	Yes
PM/PM_{10}	511/211	25/15	Yes
SO_2	407	40	Yes
SAM	41	7	Yes
VOC	176	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park (i.e. PSD Class II Areas) Therefore; multi-source modeling was not required for ambient air quality standards Class II increments. The predicted impacts in the Class I Everglades National Park (ENP) are less than the applicable significant impact levels except for the 3-hour and 24-hour SO_2 and 24-hour PM_{10} impacts. Therefore multi-source increment modeling was required for the 3–hour and 24-hour SO_2 and 24-hour PM_{10} impacts upon the ENP. The following table summarizes the maximum predicted 3-hour and 24-hour SO_2 and 24-hour PM_{10} increment consumption by the new project and by all projects in the general area since 1977.

	PM_{10} Increment Consumed in ug/m^3 and % at ENP		SO_2 Increment Consumed in ug/m^3 and % at ENP	
Averaging Time	By Project	All Sources	By Project	All Sources
24-hour	0.5 (10% of Allowable)	2.1 (42% of Allowable)	0.4 (8% of Allowable)	4.1 (82% of Allowable)
3-hour	No Analysis Required	No Analysis Required	2 (8% of Allowable)	18 (72% of Allowable)

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). 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 (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) 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, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

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

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32399-2400 Telephone: 850/488-0114 Fax: 850/922-6979	Department of Environmental Protection Southeast District Office 400 North Congress Avenue West Palm Beach, FL 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6790	Palm Beach County Public Health Unit Environmental Health & Engineering Services 901 Evernia Street West Palm Beach, Florida 33402 Telephone: 561/355-3136 Fax: 561/355-2442

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program Administrator, South Permitting Section at the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/air/permitting/construction/westcounty.htm

In the Matter of an
Application for Permit by:

Mr. Randall R. LaBauve, Vice President
Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408
_______________________________/

DEP File No. 0990646-001-AC
Draft Permit No. PSD-FL-354
FPL West County Energy Center
Two 1,250 MW Combined Cycle Units
Palm Beach County

INTENT TO ISSUE PSD PERMIT

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

The applicant, FPL, applied on April 14, 2005 (sufficient on September 12, 2005) to the Department for a PSD Permit for two nominal 1,250 megawatt combined cycle units at the proposed FPL West County Energy Center at 4000, 205th Street North in unincorporated Palm Beach County.

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

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 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 PSD Permit (Notice). 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. Pursuant to Rule 62-17.135(1)(c), F.A.C. the applicant shall have published in the appropriate newspapers the Notice no later than 10 days after the preliminary determination has been issued. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

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

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

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

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/1/06 to the persons listed:

Randall R. La Bauve, FPL*
Chair, Palm Beach County BCC
Mayor, Village of Royal Palm Beach
Mayor, Village of Wellington
John Benjamin, Everglades National Park
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Steven L. Palmer, DEP Siting Office
Darrel Graziani, DEP SED
Paul Darst, Department of Community Affairs
Jim Stormer, Palm Beach County Public Health Unit
Ken Kosky, P.E., Golder
Barbara Linkiewicz, FPL

Clerk Stamp

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

(Clerk) 3/1/06 (Date)

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company
West County Energy Center

Two Nominal 1,250-Megawatt Combined Cycle Units

Palm Beach County

DEP File No. 0990646-001-AC (PSD-FL-354)

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

March 1, 2006

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33035

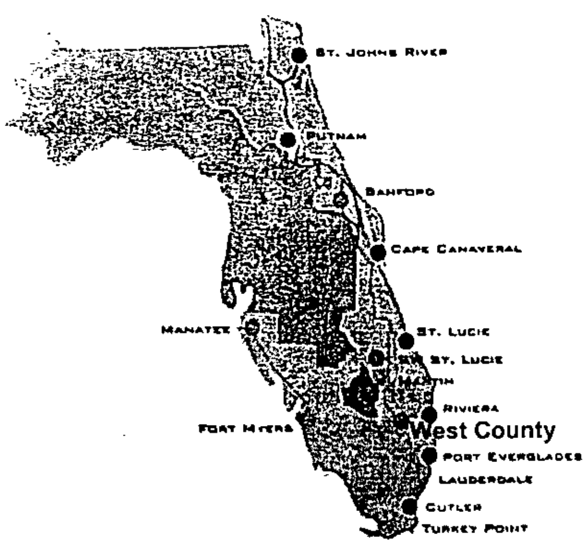
Authorized Representative:
Randall R. LaBauve, Vice President

Processing Schedule

- April 14, 2005: Received Site Certification Application (SCA) including PSD application
- June 27: Sufficiency determination issued by DEP Siting Coordination Office (SCO)
- August 12: Received Response to SCO sufficiency questions
- September 12: SCO issues determination finding SCA/PSD Application sufficient
- November 9: FP&L waives Preliminary Determination Issuance deadline
- December 2: FP&L waives Preliminary Determination Issuance deadline
- December 29: FP&L submits details regarding Mitsubishi 501G technology
- January 20, 2006 FP&L waives Preliminary Determination Issuance deadline
- March 1, 2006: Preliminary Determination issued

Facility Description and Location

The Florida Power and Light (FPL) Company proposes to construct the West County Energy Center (WCEC) at 4000 205th Street, North in unincorporated Palm Beach County. The location with respect to other FPL facilities in Florida is shown in Figure 1. The proposed WCEC site is bounded by SR 80 (Southern Boulevard) on the south, FPL 500 kV transmission lines on the west, a major electrical substation on the northwest corner, as well as mining lands to the north and east.



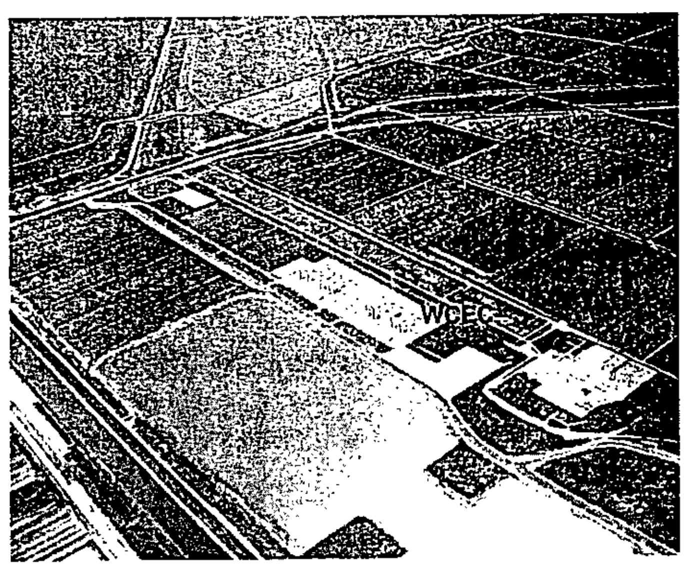


Figure 1. Proposed Location FPL WCEC **Figure 2. Aerial View, Rendition from Northeast**

The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located south of Southern Boulevard. The northwest corner of the refuge is visible in the upper left hand side of Figure 2, which is a rendition of the future plant on the proposed site looking from the northeast. The Villages of Wellington and Royal Palm Beach are located a few miles east of the site. The site is located approximately 107 km north of the PSD Class I Everglades National Park. UTM coordinates are Zone 17; 562.19 km E; 2953.04 km N.

Regulatory Categories

Standards of Performance for New Stationary Sources (NSPS). The proposed facility will be subject to one or more NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP): The proposed facility is a "Major Source" of hazardous air pollutants (HAPs) and will be subject to one or more NESHAP.

Title IV: The proposed facility will operate units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The proposed facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAPs. 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).

Prevention of Significant Deterioration (PSD): The proposed facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the proposed facility will be greater than 100 tons per year for at least one regulated pollutant. Therefore, the proposed facility is a Major Facility with respect to Rule 62-212.400, F.A.C.

Siting: The proposed facility is a steam electrical generating plant. The project will result in more than 75 MW of steam-generated electrical power and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct two "three-on-one" combined cycle units (Units 1 and 2). Each combined cycle unit will consist of: three nominal 250 megawatt (MW) "G" Class gas turbine-electrical generator sets (probably Mitsubishi Heavy Industries Model M501G) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors and gas-fired duct burners (nominal 428 mmBtu/hour, LHV); three 149 foot exhaust stacks; one 22- cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.

Additional ancillary equipment will include: four 2250 KW emergency generators; two natural gas fired fuel heaters; two 6.3 million gallon diesel fuel storage tank; two 85,000 lb/hr auxiliary steam boilers; and other associated support equipment. Following are additional project characteristics.

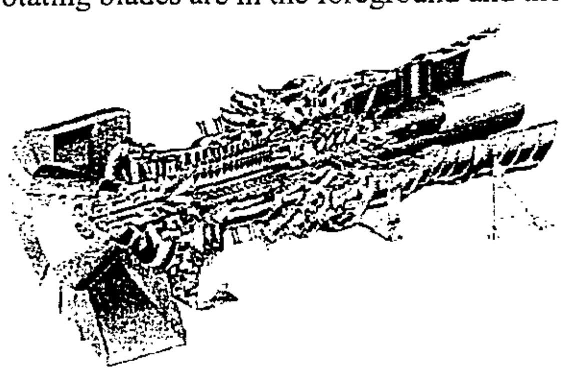
- Fuels: Each gas turbine will fire natural gas as the primary fuel and *ultra low sulfur* (0.0015% Sulfur) distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 500 hours per year per gas turbine (or equivalent) for oil firing.

- Generating Capacity: Each of the three gas turbines has a nominal generating capacity of 250 MW. Each of the three heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 500 MW. The nominal capacity of each unit is 1,250 MW.
- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ultra low sulfur (ULS) distillate oil. NO_X emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: Each gas turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at least 149 feet tall with a nominal diameter of 23 feet. The following summarizes the exhaust characteristics of each of the six combustion turbine/HRSG sets, exclusive of the 428 mmBtu/hour (LHV) duct burners:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	2333 mmBtu/hour	59° F	195° F	1,330,197
Oil	2117 mmBtu/hour	59° F	293° F	1,553,502

Project Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A longitudinal section diagram of an M501G (rotor inside of casing) from an MHI brochure is shown in the left hand side of the figures below. The photograph on the right hand side of the figure is of the rotor being lowered into the shell (not visible) of an M501G. The compressor rotating blades are in the foreground and the 4-stage expansion section is in the background.



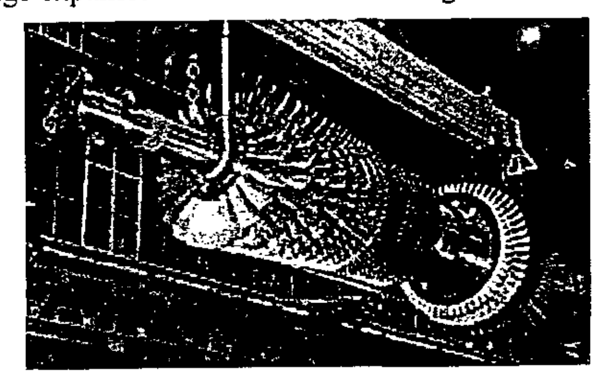


Figure 3. Longitudinal View of M501G, Photograph of Rotor (Source: MHI Website)

Ambient air is drawn into the 17-stage compressor of the M501G where it is compressed to a pressure ratio greater than 19 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate steam-cooled, can-annular, Dry Low NO_X (DLN) combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is greater than 2,700 °F.

The hot combustion gases routed through the steam-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. 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. Turbine exhaust gas is discharged at a temperature of approximately 1200 °F and high excess oxygen and is available for additional energy recovery.

Each unit will operate in combined cycle mode as depicted in Figure 4. Each of three combustion turbines per unit will drive an electric generator while the exhausted gases from each combustion turbine will raise additional steam in three heat recovery steam generators (HRSG's). The steam from the three HRSG's, in-turn, will drive a single, separate steam turbine-electrical generator per unit producing additional electrical power.

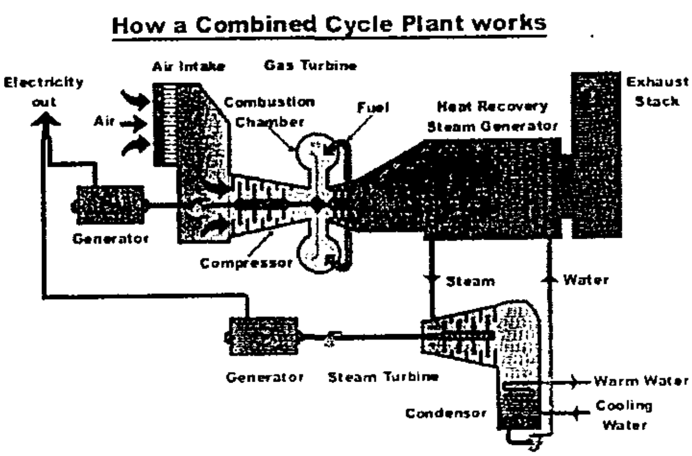


Figure 4. Combined Cycle Unit (Unfired HRSG)

In combined cycle mode, the thermal efficiency of G-Class combustion turbines approximately 58 percent (%) on the basis of lower heating value and about 53% based on the higher heating value.

- Inlet Conditioning: Evaporative cooling is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. This is typically implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2880 hours of duct burning per year for each HRSG.

Further process details are provided in the Draft BACT determination, Section 4.0 below.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The following table summarizes the applicant's initial estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, and cooling tower).

Table 1. Applicant's Initial Estimated Annual Emissions for both Combined Cycle Units

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	968	100	Yes
Pb	0.050	0.6	No
NO_X	841	40	Yes
PM/PM_{10}	511/211	25/15	Yes
SO_2	407	40	Yes
SAM	41	7	Yes
VOC	176	40	Yes

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the 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 following rules in the Florida Administrative Code.

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

Federal Regulations

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

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

Description of PSD Applicability Requirements

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

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

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for NO_X, CO, VOC, SO_2, SAM and PM/PM_{10}.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*

2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

According to Rule 62-212.400(4)(c), FAC, the applicant must at a minimum provide certain information in the application including:

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.

4.2 NO_X BACT Determinations for Combustion Turbines and Duct Burners

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 as seen on the left hand side of Figure 5. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 5, which is from a GE discussion on these principles.

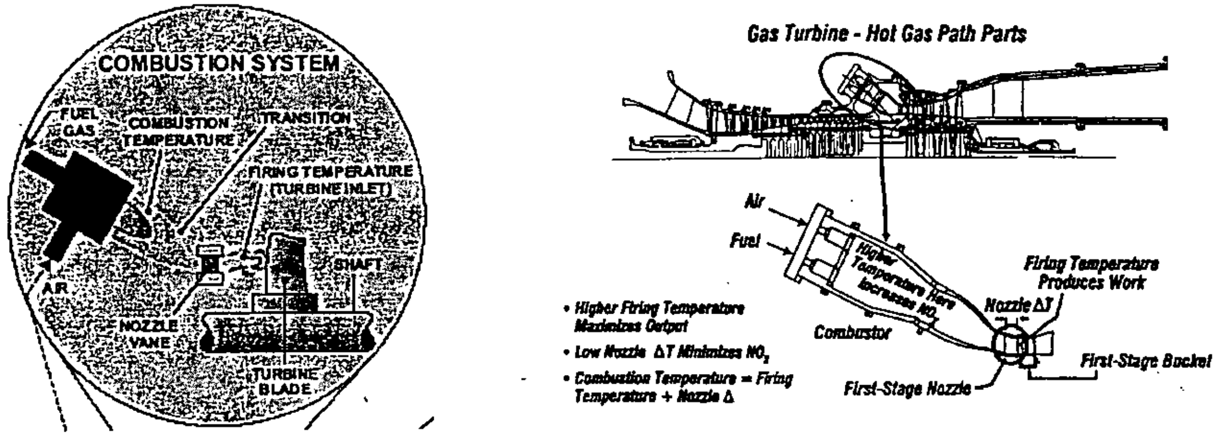


Figure 5. Relation between Combustion and Firing Temperatures and NO_X Formation

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 <u>air</u> 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 alternative of <u>steam</u> cooling is discussed below.

<u>Prompt NO_X</u> 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.

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

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the FPL project. The proposed NO_X controls will reduce these emissions significantly. For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large G-Class gas turbines is greater than 110 ppmvd @15%O_2. This constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

<u>Descriptions of Available NO_X Controls</u>

<u>Wet Injection</u>. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. 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.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below.

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. These principles are incorporated into the M501G DLN combustor shown on the left hand side of Figure 6. There is a central diffusion pilot nozzle that provides stability but ultimately limits the ability of the combustor to achieve the lowest possible NO_X emissions without further control.

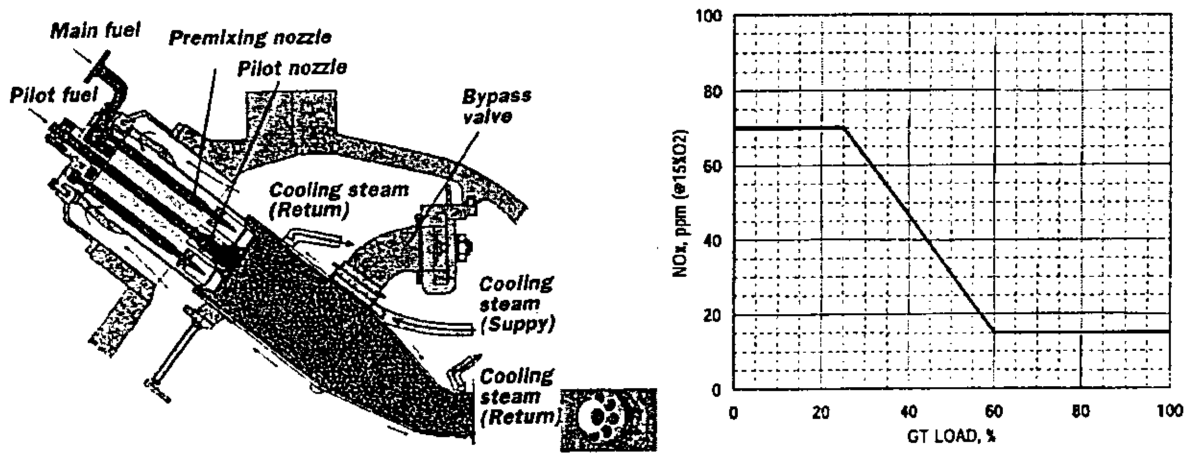


Figure 6. M501G DLN Combustor, Nozzle Block and NO_X versus Load Specification

The graph on the right hand side contains the NO_X specifications for new Mitsubishi M501G1 combustion turbines.[1] The combustor emits NO_X at concentrations less than 15 ppmvd at loads between 60 and 100 percent of capacity. The firing temperature within the 60-100% load range is between roughly 2500 and 2750 °F. The low NO_X values are an excellent achievement considering the high firing temperature.

The difference between combustion temperature and firing temperature into the first stage is minimized by steam cooling of the transition piece and first stage nozzle. Thus a lower combustion temperature (and lower NO_X) can be achieved by steam cooling compared with air cooling for a given firing temperature (equal work). Alternatively a higher firing temperature (more work, greater efficiency) can be achieved by steam cooling compared with air cooling for a given combustion temperature (equal NO_X).

It is believed that the combustor for the M501G1 can actually achieve low NO_X emissions (< 20 ppm) at lower load than suggested by the diagram. The tendency to increase NOX concentrations is mitigated by decreasing firing temperature.

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.[2] 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.

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™.[3] 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. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[4] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[5] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the FPL West County Energy Center project.

Selective Catalytic Reduction (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 routinely 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. Sulfur in fuel is no longer an issue for planned combustion turbines in the United States because of the mandated availability of ultralow sulfur (ULS) diesel fuel. ULS diesel fuel has a sulfur specification that is about as stringent as the natural gas specifications.

Figure 7 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor 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 8 is a photograph of the PEF Hines Power Block I. 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.

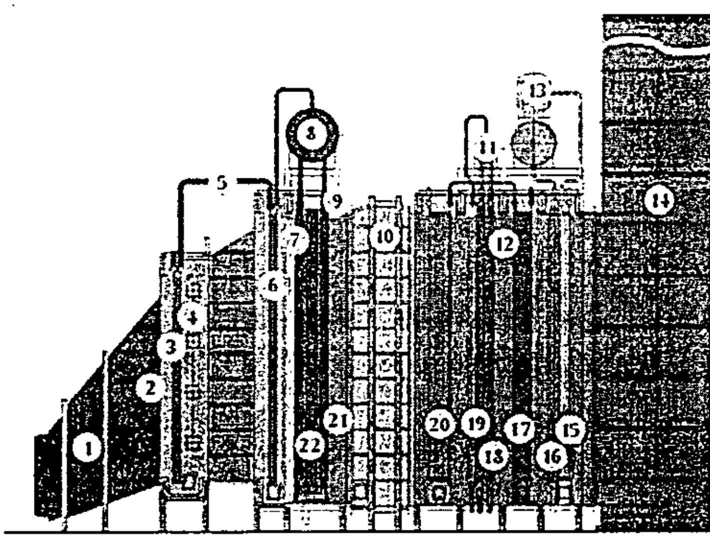


Figure 7 – Key HRSG Components (10 is SCR)

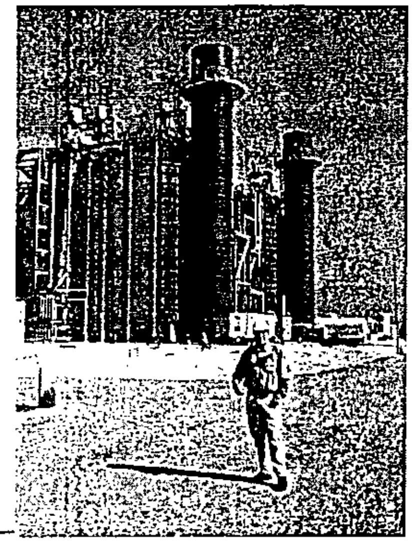


Figure 8 – PEF Hines Block I

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or ultra low sulfur distillate fuel oil. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

The Sithe Mystic Station, Massachusetts is located in an ozone non-attainment area. The project received conditional approval to commence construction in 2000 and started up in 2003.[6] It consists of four M501G combined cycle units with duct burners. Each unit has a NO_X limit of 2 ppmvd @15% O_2. One month of hour-by-hour NO_X data from Unit 82 is presented in Figure 9.

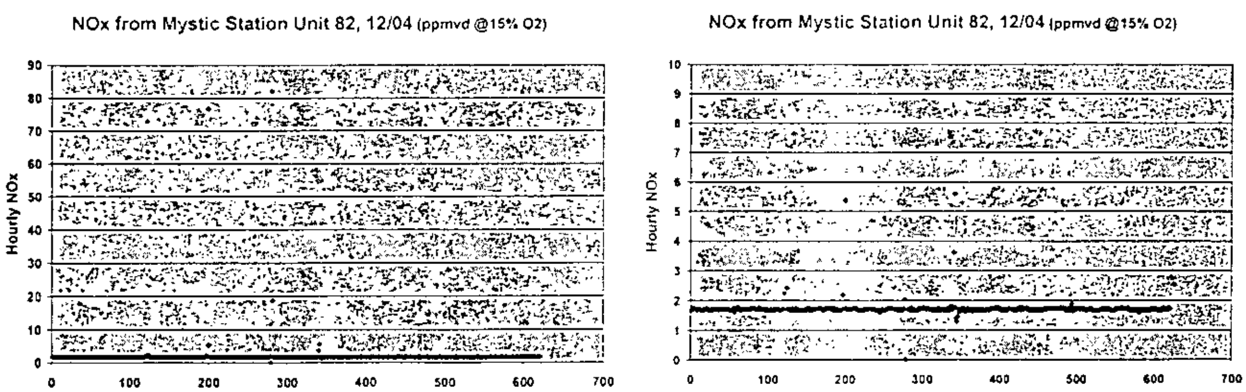


Figure 9. Hourly NO_X Data from Sithe Mystic Station, Massachusetts. December 2004

Unit 82 operated 620 hours during the month of December 2004, typically at combustion turbine electrical generation rates between 170 and 250 MW. The data on the left comprise all reported hours of operation including thirteen measurements related to startups and shutdowns. The same data on the right, in greater resolution, clearly show that, with the exception of the startup and shutdown values, the unit consistently achieved less than 2 ppmvd NO_X @15% O_2.

Since 1999, SCR has been specified for all combined cycle projects in Florida that required a BACT determination. All of the projects rely on DLN or wet injection for basic NO_X control in addition to the add-on SCR systems.

In conclusion, SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions. SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

SCONO$_X$™. This technology is an NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

SCONO$_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[7] Alstom Power was not successful in marketing the product at large facilities.

SCONO$_X$™ technology (at 2.0 ppmvd) was used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$™ can match the performance of SCR without the ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from natural gas reforming unit.

Table 2 contains averaged cost values for SCONO$_X$™ and SCR developed by the California Air Resources Board for their Legislature.[8] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 2. Cost Comparison between SCR and SCONO$_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	SCONO$_X$™	SCR/CO	SCONO$_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with SCONO$_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the SCONO$_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by FPL for the proposed 2,200 MW project also indicate a large cost difference between the two technologies. While the Department does not accept or reject either set of figures, it appears that $SCONO_X^{TM}$ is not cost-effective for the present project.

Applicant's NO_X BACT Proposal

The applicant originally proposed a BACT NO_X limit of 2.5 ppmvd @15% O_2. FPL proposed to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. FPL proposed a BACT NO_X emission limit of 10 ppmvd @15% O_2 by a combination of wet injection and SCR while burning backup ultra low sulfur fuel oil.

FPL originally submitted an analysis presuming a reduction of NO_X from 35 to 2.5 ppmvd @15% O_2. Subsequently, FPL apparently obtained a guarantee of 15 ppmvd @15% O_2 from the manufacturer of the M501G1 by DLN prior to consideration of further reduction by SCR. Following discussions with the Department, FPL agreed to values of 2.0 and 8.0 ppmvd @15% O_2 while burning natural gas and ultralow sulfur fuel oil, respectively. The average cost effectiveness was estimated by FPL to be $3,385 per ton of NO_X removed (From 15 to 2.0 ppmvd @15% O_2).

Department's Draft NO_X BACT Determinations

Table 3 includes the known determinations for M501G units. All used SCR. Based on this table, the "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average for G-Class units. The FPL West County proposal is included for comparison.

Table 3. NO_X Standards for M501G Combined Cycle Units with Duct Burners

Project Location	Capacity (MW)	NO_X Limit and Fuel (ppmvd @ 15% O_2)	Comments
Sithe Mystic, MA	1,600	2 – NG & DB (1-hr)	LAER, Startup 2003
Sithe Fore River, MA	800	2/6 – NG & DB/FO (1-hr)	LAER, Startup 2003
Wolf Hollow, TX	730	9 – NG (DB?)	BACT, Startup 2003
Covert Generating, MI	1,200	2.5 – NG & DB (24-hr)	BACT, Startup 2004
Port Westward, OR	415	2.5 – NG &DB (3-hr)	BACT, Startup ~ 2007
FPL West County, FL	2,500	2.0/8.0–NG&DB/FO (24-hr)	BACT, Startup ~2009

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

The data from the Sithe Mystic project provides reasonable assurance that a level of 2.0 ppmvd @15% O_2 can be consistently achieved. The Department will set limits of 2.0 and 8.0 ppmvd @15% O_2 while firing natural gas (with or without use of duct burners) and for the limited firing of ultralow sulfur (ULS) fuel oil, respectively. Averaging times will be 24 hours.

The Department does not consider a 1-hour averaging time to be necessary to insure continuous low NO_X levels. This provides relief from some of the small risks of occasionally exceeding the very low BACT NO_X limits.

The limits of 2.0 and 8.0 ppmvd @15% O_2 represent reductions of 98% and 92% for the gas and oil cases respectively when compared with the applicable New Source Performance Standard at 40 CFR 60, Subpart GG.

4.2 CO and VOC BACT Determination

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst.

The figure below contains CO specifications while firing natural gas and fuel oil, including the guarantee values that apply between 60 and 100%.[9]

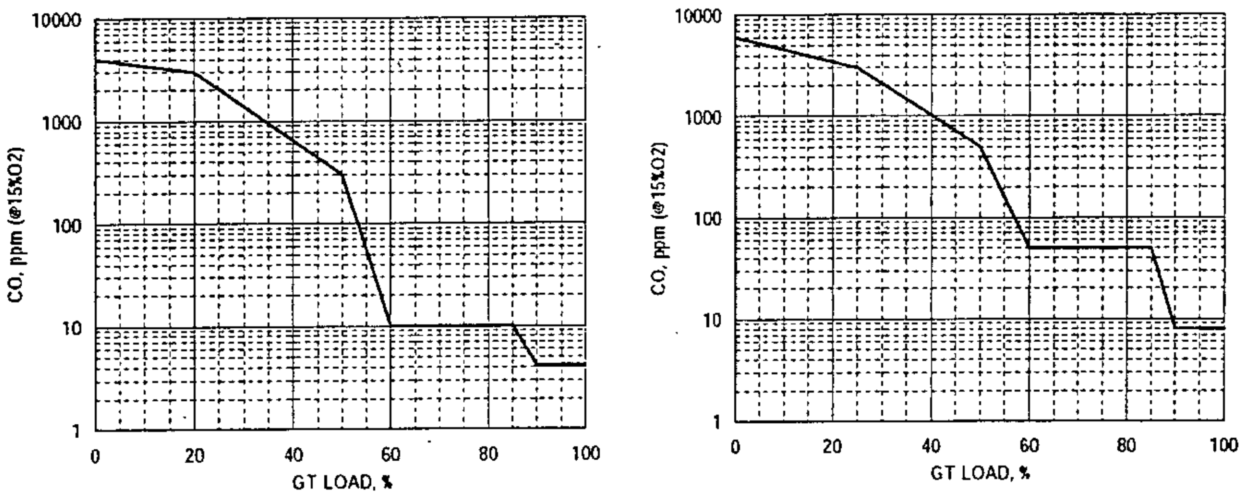


Figure 10. Expected CO versus Load while burning Gas or Fuel Oil. M501G1.

Generally the performance data on the left hand side indicate that the combustor performs very well on natural gas within the range of 60 to 100% of full load. Basically, at 60% of full load the flame and firing temperatures are great enough to destroy most CO. The graph on the right shows the characteristics while firing fuel oil.

Typically VOC concentrations are an order of magnitude less than CO concentrations. Therefore, while burning natural gas, VOC emissions will likely be less than 1 ppm while operating between 60 and 100% of full load. Similarly, VOC emissions less than 5 ppm and as low as 1 ppm are expected while firing fuel oil.

Duct Burner and Fuel Oil Considerations

The presence of a duct burner (refer to Figure 7, Component 4) complicates the evaluation somewhat. Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,200 °F) and high excess air (> 12% O_2). In the design shown in Figure 7, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6). Figure 11 shows an individual burner and an array comprising a duct burner. The hot TEG serves as combustion air for gas introduced into the burner array.

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions are present to minimize further CO and VOC concentration increases when corrected to 15% oxygen.

CO emissions while firing fuel oil should be very low, again, based on the high combustion temperature and the relatively high temperature and excess air in the TEG.

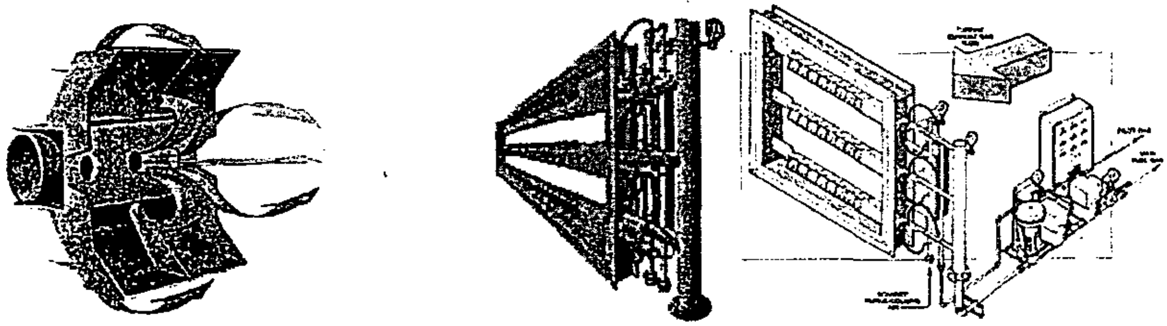


Figure 11 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

FPL's Initial CO, VOC, and PM/PM_{10} Emission Limit Determination

The known CO and VOC (and PM and ammonia) determinations for projects based on the M501G technology are presented in the following table. FPL's initial proposal (prior to selecting the M501G) is included in the table for comparison.

Table 6. CO, VOC, PM Standards for M501G Combined Cycle Units with Duct Burners

Project Location	CO – ppmvd @15% O_2	VOC – ppmv (@15% O_2)	PM – lb/mmBtu or lb/hr NH_3 – ppmvd @15% O_2
FPL West County	5/7–NG/FO (DB off, 100%, test) 7.2 – NG (DB on, 100%, test) 8.0 – All Modes, 24-hours	1.2 – NG (DB off) 1.9 – NG (DB on) 10 – FO (DB off)	10% Opacity, NH_3 = ? 12 lb/hr (NG, DB off, front+SCR) 14 lb/hr (NG, DB on, front+SCR) 69 lb/hr (FO, DB off, front+SCR)
Sithe Mystic, MA	2.0 – NG & DB (1-hr, Ox-Cat)	1.0 (DB off) 1.7 (DB on)	0.011 (32.5 lb/hr) (NG+DB) (NH_3 = 2.0 ppmvd)
Sithe Fore River, MA	2/7–NG & DB/FO (1-hr, Ox-Cat)	1.0 (DB off) 1.7 (DB on)	0.011 (32.5 lb/hr) (NG+DB) 0.05 (140 lb/hr) (FO+DB) (NH_3 = 2.0 ppmvd)
Covert Generating, MI	5 (Ox-Cat, per MHI Paper)[10] According to Permit:[11] 33.7 lb/hr (NG+DB, 24-hr)	7.7 lb/hr (NG+DB)	33.8 lb/hr (NG+DB) (NH_3 = 10 ppmvd)
Wolf Hollow, TX	33.8 (NG+DB, 24-hr)	VOC = ?	PM = ? (NH_3 = 10 ppmvd)
Port Westward, OR	4.9 (NG+DB, 3-hr, Ox-Cat)	7.7 lb (NG+DB)	(NH_3 = 8 ppmvd)

Notes: NG = CT on Natural Gas DB = Duct Burner FO = Fuel Oil

Department's CO and VOC BACT Proposal

FPL subsequently obtained high load (90-100%) guarantees from Mitsibishi of 4.1 and 8.0 ppmvd CO @15% O_2 for natural gas and fuel oil firing, respectively. The guaranteed CO emission at medium load is 10 ppmvd CO @15% O_2 while firing natural gas. Per Figure 10, expected medium load emissions are 50 ppmvd CO @15% O_2 while firing fuel oil.

The duct burners will operate only when power is required beyond what can be provided when the combustion turbine operates at full load. As long as the duct burners are used, emissions from the combustion turbine are minimized. FPL still estimates greater CO concentrations while using the duct burners than when operating the combustion turbine at full load.

On a given day, each combustion turbine/supplementary-fired HRSG can operate within the full spectrum of loads (60-100%) and fuels. FPL and the Department have agreed that a continuous 24-hour emissions limit to cover all the modes of operation will be 8.0 ppmvd @15% O_2. This and the full load proposals are consistent with recent determinations for FPL Turkey Point and FMPA Treasure Coast combined cycle projects.

Similarly an annual 12-month limit of 6 ppmvd will apply that takes into consideration the preponderance of natural gas operation at 4.1 ppmvd @15% O_2.

While FPL has requested 500 hours per year of ultralow sulfur fuel oil operation, they will rarely use fuel oil. For example Martin Combined Cycle Units 3 and 4 were permitted to fire both natural gas and fuel oil, but were never even commissioned to fire fuel oil.

With respect to the dual-fuel units, FPL advised: *"Our historical practice has been that we run on oil for limited hours each month for reliability purposes (to ensure that the systems operate properly), and from time to time, we burn oil when gas service is interrupted or other factors require us to use back-up fuel. Martin Unit 8 (2005), Fort Myers Units 3A and 3B (since 2003), Fort Lauderdale Units 4 & 5 (since 1996) and Putnam (since 1996) collectively averaged less than 100 hours of oil burning per year per unit."*[12]

The Department agrees that FPL's description is a reasonable expectation for the proposed West County Power Plant. Given the low fuel oil use and restrictive daily and annual CO stack emission concentrations, there is little benefit in installing oxidation catalyst. Furthermore, FPL successfully obtained the lowest guarantees for "G" technology units specified to-date prior to consideration of additional control by catalyst. FPL can install oxidation catalyst at a future date to meet the low CO emission limits if circumstances such as very high natural gas prices cause greater operation at low load conditions characteristic of higher CO concentrations.

The updated VOC proposal while burning natural gas of 1.2 and 1.5 ppmvd @15% O_2 with the duct burner off and on, respectively, is acceptable. The updated proposal of 6.0 ppmvd @15% O_2 while burning fuel oil appears high. However, the most likely expectation is that VOC emissions will be approximately 1 ppmvd and 5 ppmvd @15% for high and medium load, respectively, during the brief periods of fuel oil firing.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT).

4.3 Sulfur Dioxide (SO2) and Sulfuric Acid Mist (SAM) BACT Determination

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.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed as BACT the use of ultra low sulfur fuel oil (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF). For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8% by weight.

FPL estimated 206 tons per year of SO_2 and 20 tons per year of sulfuric acid mist (SAM) per combined cycle unit. This equates to 412 and 40 TPY for SO2 and SAM respectively from the two combined cycle units. Realistically, annual emissions will be approximately one-fourth of the estimated values because the sulfur concentration in the pipeline gas is typically closer to 0.5 gr/100 SCF than to 2 gr/100 SCF. The Department accepts FPL's BACT proposal for SO_2 and SAM. This approach is consistent with other recently permitted projects.

4.4 Particulate Matter (PM/PM10) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion. Natural gas and ultra low sulfur distillate fuel oil will be the only fuels fired and are 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. The ultra low sulfur (ULS) fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 500 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

As previously discussed, there will be emissions of NO_X, SO_2, SAM and ammonia (NH_3). These pollutants are ultimately converted to very fine ammonium nitrate and ammonium sulfate species in the environment. The NO_X control technology of SCR can increase PM/PM_{10} emissions from the stack due to formation of ammonium sulfates prior to exiting.

The PM/PM_{10} emission limits for M501G projects are included in Table 6. Comparison is not simple because some of the limits may represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter. The values shown as FPL's proposal reflect the filterable portion in addition to PM/PM_{10} formed by the conversion of ammonia slip into ammoniated sulfate emissions. FPL proposed only the opacity limit of 10% and not a hard PM/PM_{10} limitation.

The Department notes that FPL will use ultra low sulfur (ULS) fuel oil. ULS fuel oil contains less than 0.0015% sulfur compared with the present 0.05% sulfur specification of low sulfur fuel oil.

The very high combustion temperatures, use of inherently clean fuel (including ULS fuel oil), and a relatively low ammonia emission limit will insure that PM/PM_{10} emissions will be very low and likely less than estimated by FPL. The Department will adopt FPL's proposal of 10% opacity as BACT in conjunction with the use of inherently clean fuels and high temperature, high excess air combustion.

The Department proposes a relatively low ammonia limit of 5 ppmvd @15% O_2 as part of the PM/PM_{10} BACT determination. The low SO_2, NO_X, NH_3, and PM/PM_{10} strategies give assurances that direct $PM_{2.5}$ emissions and formation of $PM_{2.5}$ in the environment by precursors emitted from the project will be minimized.

Cooling Tower PM Emissions

The applicant's preliminary design includes a 26-cell mechanical draft cooling tower for each combined cycle unit with the following specifications: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators with a drift rate of no more than 0.0005 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water.

FPL estimates annual emissions of 67 tons of PM per cooling tower due to drift losses assuming a drift rate of 0.0005%. PM_{10} emissions are projected to be approximately 5 TPY per cooling tower.

The Department determines the draft BACT to be a design drift rate of no more than 0.0005% of the circulating water flow rate. At this level, maximum potential PM and PM_{10} emissions from the cooling tower are expected to be on the order of 134 and 10 TPY respectively from the two cooling towers.

Applicant's PM/PM_{10} Proposal

FP&L proposes PM/PM_{10} BACT as opacity limit of 10%. FPL proposes PM control from the cooling tower to be accomplished by a 0.0005% drift rate design limitation.

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbines may fire distillate oil as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd.
- The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

4.5 Department Draft BACT Determinations for Combustion Turbines and Duct Burners

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 7. Draft BACT Determination

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[g]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CT)	8.0	42.0	8.0, 24-hr 6, 12-month[h]
	Gas	CT & Duct Burner (DB)	7.6	52.5	
		CT Normal	4.1	23.2	
NO_X[b]	Oil	CT	8.0	82.4	8.0, 24-hr
	Gas	CT & DB	2.0	24.2	2.0, 24-hr
		CT Normal	2.0	20.0	
PM/PM_{10}[c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur fuel oil Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC[e]	Oil	CT	6.0	19.6	NA
	Gas	CT & DB	1.5	5.4	
		CT Normal	1.2	4.1	
Ammonia[f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner modes. The stacks test limits apply only at high load (90-100% of the combustion turbine capacity).

b. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the combustion turbine capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any combustion turbine/supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

4.6 New Source Performance Standards Applicable to Gas Turbines and Duct Burners

Combustion Turbines

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

- NO_X (gas) ≤ 75 ppmvd @ 15% O_2 (assuming 25% LHV simple cycle efficiency);
- NO_X (oil) ≤ 114 ppmvd @ 15% O_2 (corrected for approximate 38% LHV efficiency characteristic of G-Class units); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

A more recent standard was proposed by EPA on February 18, 2005. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (gas) ≤0.39 lb/megawatt-hour (lb/MWH);
- NO_X (oil) ≤1.2 lb/MWH; and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% (500 ppmw) by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. This is obvious in the case of the Subpart GG standards (2 and 8 ppmvd NO_X @15% O_2). These values are approximately equal to 0.06 and 0.22 lb NO_X/MWH while burning gas and fuel oil respectively..

The final rule will be applicable to the WCEC at the time of publication in the Federal Register. When the rule becomes final, WCEC may no longer be subject to NSPS Subparts Da and GG.

Duct Burners

Each HRSG has a gas-fired duct burner (DB) with a maximum heat input rate of 475 MMBtu per hour (MMBtu/hr, HHV). This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NO_X ≤ 1.6 lb/MW-hr (gross)
- SO_2 ≤ 0.20 lb/MMBtu
- PM ≤ 0.03 lb/MMBtu

The Department's proposed BACT NO_X standard for the combination of gas turbine and duct burner emissions is equivalent to approximately 0.06 lb/MW-hr for NO_X. The specifications for the ultra low sulfur fuel oil and natural gas insure that the NSPS PM and SO_2 emission limits for the duct burners will easily be met.

As mentioned in the previous section, Subpart Da may not apply to the WCEC if and when Subpart KKKK is promulgated as a final NSPS. An Appendix to the permit will summarize applicable federal requirements.

4.7 National Emission Standards for Hazardous Air Pollutants Applicable to Gas Turbines

The West County Energy Center will be a new major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NESHAP Subpart YYYY, which became final on March 5, 2004.[13] According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[14] EPA has stayed the applicability of YYYY to units such as those proposed for the West County Energy Center project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

FP&L proposes to meet the limit proposed in YYYY of 91 ppbvd. The Department believes the formaldehyde emission limit will be met given the proposed BACT CO limits of 8.0 and 6 ppmvd @15% O_2 for daily and annual operation respectively. It is also expected that the units will easily demonstrate compliance with the formaldehyde limit during the initial and annual test requirements.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

4.8 BACT Determinations for Auxiliary Boilers

One gas-fired auxiliary boiler is required for each combined cycle unit. The primary purpose of the auxiliary boiler is to provide steam for combustor cooling until steam of sufficient quality can be provided by the HRSG.

The specifications for the auxiliary boilers are as follows:

- Nebraska Boiler or equivalent;
- Usage of 500 hours per year;
- Maximum heat input rate of 99.8 MMBtu/hr heat input; and
- Steam capacity: 85,000 lb/hr.

A recent BACT determination was conducted for the Port Westward, Oregon project. An auxiliary boiler was required for startup of an M501G combined cycle unit. A 91 MMBtu auxiliary boiler was specified for that project.

The state of Oregon conducted a search of BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC) in early 2005. Approximately 20 RBLC determinations were reviewed by the State of Oregon for auxiliary boilers in the range of 10 to 100 MMBtu/hr that are used in support of combined cycle projects. Separate tables were developed for NO_X, SO_2, CO, VOC, and PM/PM_{10}.

The ranges from the Oregon survey are presented in the following table along with the limits set for the M501G projects for which the auxiliary boiler limits are known. The auxiliary boilers considered are in the range of 10 to 100 MMBtu/hr. All of the auxiliary boilers listed for M501G projects are between 90 and 100 MMBtu/hr.

The limits proposed by FPL for the West County project are included for comparison. NSPS and NESHAP requirements that are possibly applicable to the auxiliary boilers are also included. Subpart Db requirements, which apply to boilers that are 100 MMBtu/hr or greater are included because the FPL project appears to specify a nominal 100 MMBtu/hr boiler. The 99.8 MMBtu/hr specification set by FPL must relate to a physical capacity rather than a permit condition.

Table 8. CO, NO_X, VOC, PM Standards – Auxiliary Boilers for Combined Cycle Units

Project Location	CO (lb/MMBtu)	NO_X (lb/MMBtu)	VOC lb/MMBtu	PM/PM_{10} (lb/MMBtu)
RBLC Survey	0.016 – 0.15	0.01 – 0.23	0.004 – 0.018	0.0042 – 0.012
Port Westward, OR	0.08	0.05	0.005	0.002
Sithe Mystic, MA	0.08	0.035	0.008	0.007
Sithe Fore River, MA	0.08 and 100 ppm @3% O_2	0.035/0.10 (NG/FO)	0.008/0.004 (NG/FO)	0.007/0.08 (NG/FO)
Covert Generating, MI		DLB & FGR		
FPL West County, FL	0.18	0.10	0.005	0.002
NSPS Subpart Db		0.20		
NSPS Subpart Dc	Boilers between 10 and 100 mmBtu/hr - Record Keeping Required			
NESHAP Subpart DDDD	400 ppm@3% O_2			

Notes: NG = Natural Gas FO = Fuel Oil LNB = Low NO_X Burners FGR = Flue Gas Recirculation

The NO_X and CO values proposed by FPL for the WCEC project are greater than most of the projects in the Oregon survey or the other M501G projects. Even though Michigan did not set limits for the auxiliary boiler at Covert Generating, it is obvious that the specifications for Low NO_X Burners (LNB's)and Flue Gas Recirculation (FGR) will yield very low NO_X emissions. The Department does not have the details from the Wolf Hollow, Texas M501G project.

The auxiliary boilers will be used in the WCEC for the same purpose as they are used in the other M501G projects. The Department will adopt the NO_X and CO values from the Oregon determination as BACT. These values can be achieved by numerous suppliers by good combustion techniques and LNB's without resorting to catalysts, ultra LNB's, or FGR. The annual PM/PM_{10} and VOC emissions are estimated by FPL at less than 1 TPY.

4.9 <u>BACT Determinations for Emergency Generators</u>

Two standby emergency generators are included for each combined cycle unit. These will be used when electricity is not available to the site, such as during hurricanes. According to the application, these would be classified as insignificant emission units. However, a BACT determination is required because BACT applies on the entire facility.

FPL included, as an example, information on Caterpillar Gen Set standby emergency generators with the following specifications:

- Caterpillar Model 3516 engine with Frame 828, Type SR4B generator (or equivalent);
- Usage of 500 hours per year;
- Engine rated at 3,120 Brake Horse Power (BHP); and
- Generator rated at 2,250 kW.

On July 11, 2005 EPA proposed Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ICE).[15] The values applicable to generators sets in the size category of the emergency generators proposed by FPL are given in the following table.

Table 9. EPA Non-road Stationary Compression ICE Standards, grams/bhp-hr

Engine Power	Type	Tier	CO	HC	NMHC+ NO_X	NO_X	PM
2,250 kW 3,120 hp	Emergency	1 (2007)	8.5	1.0		6.9	0.4
	Stationary	2 (2007)	2.6		4.8		0.12
	Emergency	2 (2011)	2.6		4.8		0.12
	Stationary	4 (2011)	2.6		0.30 (NMHC)	0.50	0.07
	Stationary	4 (2015)	2.6		0.14 (NMHC)	0.50	0.022

Notes: bhp = brake horse power HC = hydrocarbons NMHC non-methane hydrocarbons

Emergency engines built after April 1 2006 must comply with Tier 1. Beginning in 2007, EPA Tier 1 certification is required. Tier 1 Certification will be allowed for emergency engines until 2011 when Tier 2 EPA Certification will be required.

The Department accepts the values given for emergency ICE as BACT in conjunction with use of ultralow sulfur (ULS) fuel oil. Use of ULS fuel oil will result in substantially less PM than indicated for the Tier 1 and Tier 2 requirements above and will also minimize PM_{10}, and $PM_{2.5}$ emissions and precursors.

As emergency generators, these units will be subject to the notification requirements of 40 CFR 63, Subpart ZZZZ – NESHAP for Reciprocating Internal Combustors Engines.

4.10 BACT Determinations for Natural Gas Heaters

Two natural gas heaters are required for the project. The purpose of these units is to heat natural gas above dew point temperature and prevent condensation.

FPL included, as an example, specifications for the gas heaters are as follows:

- Hannover Compression Company or equivalent;
- Continuous use although actual use will be much less; and
- Maximum heat input rate of 10 MMBtu/hr heat input.

Table 10. Proposed Emissions from Natural Gas-fired Fuel Heaters

SO_2	NO_X	CO	VOC	PM
2 gr/100 SCF	0.095 lb/MMBtu	0.08 lb/MMBtu	0.005 lb/mmBtu	0.002 lb/mmBtu

According to an interpretive memorandum by EPA in response to a Department inquiry, gas heaters in the subject size category are subject to 40 CFR 60, Subpart Dc.

4.11 BACT Determinations for Emergency Fire Pump Engines

Emergency fire pump engines were not mentioned in the application. However they are obviously project requirements. This category was included in the Standards of Performance for Stationary Compression ICE discussed in the previous section.

The standards vary depending on the size of the engine. For example, the standards for engines from model year 2007 are given in the following table:

Table 11. EPA Proposed Emergency Fire Pump Standards, grams/bhp-hr

Size (hp)	CO	$NMHC+NO_X$	PM
< 11	6.0	7.8	0.75
11 to < 25	4.9	7.1	0.60
25 to < 50	4.1	7.1	0.60
50 to < 175	3.7	7.8	0.60
175 and greater	2.6	7.8	0.40

Notes: bhp = brake horse power NMHC non-methane hydrocarbons

The Department proposes BACT for the emergency generators as compliance with the proposed standards and use of 0.05% sulfur fuel oil. Even though ULS fuel oil will be available on-site, there is no reason to require it given that any fire emissions will overwhelm the benefits of ULS fuel oil.

5. PERIODS OF EXCESS EMISSIONS

5.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

5.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "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." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from FPL regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases:

- For the very infrequent oil-to-gas and gas-to-oil fuel switching, excess emissions shall not exceed 2 hour in any 24-hour period.
- Steam turbine startups occur as little as once during a ten-year period. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 8 hours in any 24-hr period. A cold startup of the "steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown lasting at least 48 hours.
- Gas turbine/HRSG startups are infrequent but occur more often than steam turbine startups. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed 4 hours in any 24-hr period. A cold startup of a "gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period. Short startup is enhanced by the use of the auxiliary steam generators that assist in heating surfaces and provide high quality steam for transition piece and nozzle cooling.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

Combined Cycle Operation with Dump Condenser: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

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

6.2 Major Stationary Sources in Palm Beach County

The current largest stationary sources of air pollution in Palm Beach County are listed below. The information is from annual operating reports submitted to the Department.

Table 12. Major Sources of NO_X in Palm Beach County (2004)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	3808
Palm Beach County SWA	Resource Recovery Facility	1121
New Hope Power Partnership	Okeelanta Cogeneration Plant	872
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	861
Florida Power & Light	**West County Energy (proposed)**	**856**
U.S. Sugar Corp.	Bryant Mill	443
Osceola Farms	Osceola Farms	348
United Technologies Corp.	Pratt & Whitney Aircraft	238
Atlantic Sugar Association	Atlantic Sugar Mill	240

Table 13. Largest Sources of SO_2 in Palm Beach County (2004)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	11410
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	646
Florida Power & Light	**West County Energy (proposed)**	**411**
Atlantic Sugar Association	Atlantic Sugar Mill	351
Palm Beach County SWA	Resource Recovery Facility	251
New Hope Power Partnership	Okeelanta Cogeneration Plant	230

Table 14. Largest Sources of PM in Palm Beach County (2004)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	923
Florida Power & Light	**West County Energy (proposed)**	**652**
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	440
Osceola Farms	Osceola Farms	287
US Sugar Corporation	Bryant Sugar Mill	260
Atlantic Sugar Association	Atlantic Sugar Mill	240

Table 15. Largest Sources of CO in Palm Beach County (2004)

Owner	Site Name	Tons per year
U.S. Sugar Corp.	Bryant Mill	11,354
Osceola Farms	Osceola Farms	8063
Florida Power & Light	**West County Energy (proposed)**	**2020**
New Hope Power Partnership	Okeelanta Cogeneration Plant	1517
Atlantic Sugar Association	Atlantic Sugar Mill	1342
New Hope Power Partnership	Okeelanta Cogeneration Plant	230

Table 16. Largest Sources of VOC in Palm Beach County (2004)

Owner	Site Name	Tons per year
US Sugar Corporation	Bryant Sugar Mill	1365
Osceola Farms	Osceola Farms	667
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	584
Atlantic Sugar Association	Atlantic Sugar Mill	477
Florida Power & Light	**West County Energy (proposed)**	**176**
George Weston Bakeries, Inc.	Arnold and Thomas Bakery	65

6.3 Air Quality and Monitoring in the Palm Beach County

The Palm Beach County Health Department operates twelve monitors at seven sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, NO_2 and SO_2. The 2004 monitoring network is shown in the figure below.

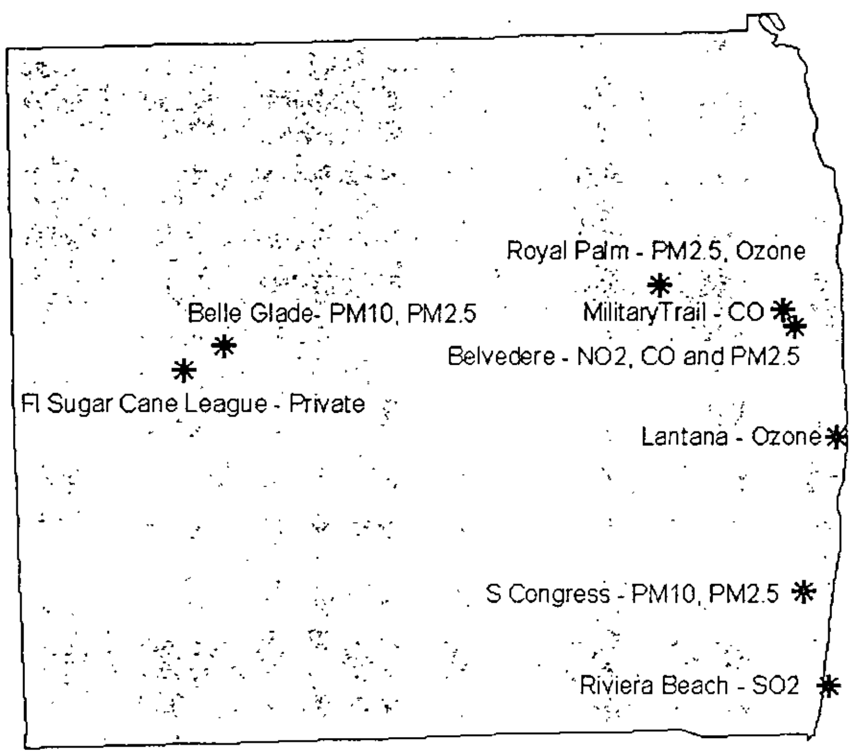


Figure 12. Palm Beach County Health Department Ambient Air Monitoring Network

Measured ambient air quality information is summarized in the following table.

Table 17. Ambient Air Quality in Palm Beach County Nearest to Project Site (2004)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Belle Glade	24-hour	31	30		150 [a]	ug/m^3
		Annual			17*	50 [b]	ug/m^3
SO_2	Riviera Beach	3-hour	2	2		500 [a]	ppb
		24-hour	1	1		100[a]	ppb
		Annual			1*	20 [b]	ppb
NO_2	Palm Beach	Annual			10*	53 [b]	ppb
CO	West Palm Beach Military Trail	1-hour	4	4		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Royal Palm Beach	1-hour	0.080	0.077		0.12 [C]	ppm
		8-hour	0.072	0.069		0.08 [C]	ppm

* The Mean does not satisfy summary criteria due to missing data.
a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels, at least at the monitoring locations. One exception is ozone because it is formed from precursors that are clearly available (NO_X and VOC) from local industrial and transportation emissions. The tendency to form ozone is accentuated by hot ambient temperature, solar insolation, high pressure, and relatively low wind speed. Such conditions when combined with cyclical drought or Everglades fires have the greatest potential to cause ozone exceedances.

Although low CO concentrations are recorded at the single monitor located on Military Trail, it is likely that CO concentrations will occasionally be greater in the area of sugar cane farming and milling due to fires and inefficient combustion of moist bagasse.

6.4 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

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 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 3 kilometers from the facility. From 3.5 to 10 kilometers, Cartesian receptors with a spacing of 500 meters were used.

For the Class I analysis 251 discrete receptors located at the ENP were used. These receptors represent a subset of receptors provided by the National Park Service.

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP) except for PM_{10} on a 24-hour basis. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 18. Maximum Projected Air Quality Impacts from FPL West County Energy Center for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	~3	60	NO
	24-Hour	4	5	~3	260	NO
	3-Hour	14	25	~5	1300	NO
PM_{10}	Annual	0.3	1	~17	50	NO
	24-Hour	11	5	~31	150	YES
CO	8-Hour	52	500	~2300	10,000	NO
	1-Hour	121	2000	~4600	40,000	NO
NO_2	Annual	0.4	1	~19	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. SO_2, Annual PM_{10}, CO and NO_X are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 105 km to the south of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from SO_2, annual PM_{10}, and NO_2 are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required for these pollutants.

Maximum predicted impacts from 24-Hour PM_{10} are greater than the applicable SILs for the Class I area. Although the values are miniscule compared with the ambient air quality standards given in the previous table, additional modeling was required as discussed below.

Table 19. Maximum Air Quality Impacts from the FP&L West County Energy Center Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.006	0.2	NO
	24-hour	0.4	0.3	YES
NO_2	Annual	0.004	0.1	NO
SO_2	Annual	0.004	0.1	NO
	24-hour	0.1	0.2	NO
	3-hour	0.4	1	NO

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels except for PM_{10} on a 24-hour basis. Therefore, no pre-construction monitoring is required for those pollutants except for PM_{10} on a 24-hour basis.

Table 20. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	11	10	~31	YES
NO_2	Annual	0.4	14	~19	NO
SO_2	24-hour	4	13	~3	NO
CO	8-hour	52	575	~4600	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC emissions from the project to be 176 tons per year. Therefore, preconstruction monitoring for ozone is required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for 24-Hour PM_{10} in the ENP Class I area and Class II area;
- A Preconstruction Monitoring analysis for 24-Hour PM_{10} and ozone (VOC);
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. 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 at Palm Beach International Airport. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996. Meteorological surface data used were from Tampa, Daytona Beach, Vero Beach, Fort Myers, Key West, Miami, West Palm Beach and Orlando. Meteorological upper air data used were from Ruskin, Key West and West Palm Beach. Hourly precipitation data were obtained from 23 stations around the central and southern 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, is 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.

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. The maximum predicted 24-hour PM_{10} PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of the West County Energy Center are shown in the following table.

Table 21. PSD Class II Increment Analysis

Pollutant	Averaging Time	2^{nd} Highest-High All Sources Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	9.3	30	NO

Through a "Development Order" by the county of Palm Beach, the county requested that the applicant provide an Increment analysis for annual PM_{10}, SO_2 and NO_X to determine what percentage of the Class II Increment the project was going to consume. The "Order" permits the project to be built as long as the impacts are not expected to consume more than 50% of the Increment. This analysis was also submitted to the Department. Results show that the project impacts are below 50% of the Increment for PM_{10}, SO_2 and NO_X for all averaging times however, the Department did not review this modeling since it was not required regarding this PSD analysis.

The proposed project is for 2,500 MW total. The modeling results in the Tables of this Draft reflect this capacity. However, the "Ultimate Site Capacity" is expected to be 3300 MW. The Increment modeling for the county was based on this capacity. Modeling based on 3300 MW was also submitted to the Department as part of the Site Certification requirements. The results of this modeling concluded that the project would still be less than the Allowable Increment for PM_{10} on a 24-hour basis. The 24-hour PM_{10} high, second-high for 3300MW capacity was predicted to be 9.7 ($\mu g/m^3$).

Multi-source PSD Class I Increment Analysis

The maximum predicted 24-hour PM_{10} PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table.

Table 22. PSD Class I Increment Analysis – ENP

Pollutant	Averaging Time	2nd Highest-High All Sources Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	1.9	5	NO

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Table 23. Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
PM_{10}	24-hour	23.1	30	53.1	NO	150

Ozone

Ozone is an area-wide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation). According to the applicant, in 1999, Palm Beach County had total emissions of NO_X and VOC from stationary sources of 11,555 TPY and 2,557 TPY respectively. When adding in the main VOC contributor, mobile sources, the total VOC TPY is 54,600.

The West County Energy Center will add 856 TPY of NO_X and 176 TPY of VOC. The proposed facility will have very low emissions per unit of energy produced, but will still contribute appreciably to regional NO_X loading. VOC emissions will add less than 1% of regional VOC emissions.

In the near future, many existing power plants and other industries that contribute to visibility impairment will reduce emissions of NO_X and SO_2 pursuant to the Clean Air Interstate Rule (CAIR) and the requirements of Best Available Retrofit Technology (BART). A number of the plants included in the CAIR and BART process are located in the Tri-County Area (Miami-Dade, Broward, and Palm Beach Counties).

To conclusively prove whether or not the 856 tons of NO_X and 176 tons of VOC will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. The uncertainty in any regional ozone model would be greater than the contribution from this project.

Preconstruction Monitoring Analysis for 24-hour PM_{10} and Ozone

The applicant provided an ozone and PM_{10} Ambient Air Quality analysis for the area of Palm beach County closest to the project site. There is an ozone monitoring site 8 miles to the east of the project site and a PM_{10} monitor 17 miles to the west of the project site. Both of which are close to the proposed project and are representative of the air quality in the vicinity of the project. Therefore, placing preconstruction monitors at the project site is not needed, nor required to obtain background air quality concentrations.

The air quality in the vicinity of the project is detailed in above sections. The county is in attainment for both ozone and PM_{10}. PM_{10} modeling also shows that the proposed project will not contribute to a violation of the standard.

6.5 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from the natural gas and distillate oil fired gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations 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 considerably less than the respective AAQS.

Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife will be minimal or insignificant. The following example is instructive.

According to the applicant, lichens are a plant species in the area of the project that are sensitive to air pollutants. SO_2 levels of 200-400 $\mu g/m^3$ for a 6 hour period in the course of a week for 10 weeks can lead to adverse impacts. SO_2 impacts from the West County Energy Center will be much less than these levels and therefore, will not contribute to adverse impacts on vegetation such as lichens.

Air pollutants can also adversely impact wildlife. According to the application, rats and hamsters have decreased respiratory disease defenses when exposed to levels of 100 μg $NiCl_2/m^3$ continuously for 2 hours. Short-term PM_{10} levels predicted from the West County Energy Center will be well below this level and therefore, will not contribute to adverse impacts on wildlife, such as rats and hamsters.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are less than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

According to the applicant, the predicted deposition rates of sulfur and nitrogen of 0.0032 and 0.0022 kg/ha/yr respectively, impacts are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

The low NO_X limit coupled with the use of ultra low sulfur fuel oil and inherently clean natural gas will minimize any possible effects due to sulfur and nitrogen deposition. Additionally the fuels are extremely low in mercury content. The very low sulfur deposition rate from the proposed project will also minimize activation of mercury in the soils by sulfur reducing bacteria.

Impact on Visibility:

The applicant submitted a regional haze analysis for the ENP. The analysis included modeling from the CALPUFF model.

Despite FPL's initial BACT proposals to minimize SO_2, NO_X, and PM, the CALPUFF model predicts modeled impacts above the 5% visibility impairment based on criteria from the NPS. If the facility continuously operates on fuel oil, impairment can occur during 6 days in three years. Because of the limitation in fuel oil use, the probability that the meteorology on a given day which lead to visibility impairment will coincide is low and the most probable expectation is that there will be no days of visibility impairment over a period of three years. The revised (lower) NOX proposals will further mitigate effects on visibility.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 350 additional workers will be needed over the 36-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the new facility will require few new permanent employees, which will cause no significant impact on the local area.

The project is a response to state-wide electrical growth and the legal requirement that certain investor owned utilities in Florida maintain a 20 percent electrical reserve. This project is one of several projects identified by FP&L in its annual 10 year plans submitted to the Public Service Commission.

Overall the project will not cause additional growth in the given area, but is a response to projected state-wide electrical power demand growth. Although the project could have been located elsewhere in Southeast Florida, the exact location is the result of economic optimization and transmission constraints.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, population growth in the area of the proposed project, Palm Beach County, has increased 128% from 1977 to 2000. The number of residential households has also increased in the county, 91% from 1977 to 2001. During this time period, the number of those employed in the county grew about 181%. Transportation in the county also grew in terms of vehicle miles traveled by 69 percent over the same time period.

The applicant addressed industrial growth in Palm Beach County as well. The manufacturing industry has seen a 49% employee increase from 1977-2000 but even greater, the agricultural industry saw about a 513% increase in employees (1977-2000). Existing Utility Facilities in Palm Beach County include the FPL Riviera Facility and Lake Worth Utility.

Despite the growth in Southeast Florida, air quality has improved as evidenced by the redesignation of the Tri-County (Broward, Miami-Dade, and Palm Beach) area to attainment status with respect to the ozone standard.

Endangered Species Considerations

The purpose of the ESA is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.[16] Under the law, species may be listed as either "endangered" or "threatened".

Endangered means a species is in danger of extinction throughout all or a significant portion of its range. Threatened means a species is likely to become endangered within the foreseeable future. All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened.

While state PSD permits are not generally reviewed for adherence with the Endangered Species Act, the State of Florida's Power Plant Certification process requires an assessment of existing ecology and determination of project impacts. Chapter 2 of the Site Certification Application includes a characterization of the existing environment including vegetation, land use and ecology. Chapters 4 and 5 address the effects of construction and operation on ecological systems aquatic and terrestrial ecology. These sections are available at State and local environmental program offices.

According to the U. S. Fish and Wildlife Service (F&WS) website at there were 111 threatened or endangered species (per the federal list) in Florida on May 18, 2004. The reader is referred to the following website: http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=FL

For reference, the F&WS recently noticed the availability of an implementation schedule for the South Florida Multi-Species Recovery Plan designed to restore endangered or threatened animals and plants to the point where they are again secure, self sustaining components of their ecosystems.[17]

According to the application, federally listed endangered species known to occur in Palm Beach County include several kinds of turtles, the peregrine falcon, the snail kite, the wood stork, the red cockaded woodpecker, the Florida Panther, the manatee, the American crocodile, and at least five plants or lichens. There is also a State listing that is more extensive and stringent than the federal one. The two lists include numerous threatened species, species of special concern, and candidates for listing.

According to FPL's application, the precise project site has no endangered species. According to the statement in the ecological impact section "the site does not contain any habitat suitable for endangered or threatened species."

The application recognizes the existence of the Arthur M. Marshall Loxahatchee National Wildlife Refuge (ARM Loxahatchee NWR) in close proximity south of the proposed site. The A.R.M. Loxahatchee NWR (see Figure 13) is operated by the U.S. Fish and Wildlife Service (U.S. F&WS). It is described in its website at: http://loxahatchee.fws.gov/Refuge/index.asp

According to the website the refuge is "the last northernmost portion of the unique Everglades. With over 221 square miles of Everglades habitat, A.R.M. Loxahatchee National Wildlife Refuge is home to the American alligator and the endangered Everglades snail kite. In any given year, as many as 257 species of birds may use the refuge's diverse wetland habitats."

Figure 13. Location of ARM Loxahatchee NWR, Slough, Wet Prairie Habitat, Snail Kite

FPL is known to have an active manatee programs in the vicinity of its conventional coastal power plants where the mammals congregate near the thermal discharges. The Riviera Power Plant in Palm Beach County is one such site where FPL maintained a Manatee Viewing Area until it was closed due to security concerns.

FPL provided documentation of a meeting with the U.S. F&WS South Florida Field Office representatives and their South Florida Ecological Services personnel in Vero Beach.[18] They provided the ecology sections of the Site Certification Application. The Department is not aware of any further requirements or consultation provided by the U.S. F&WS related to the Endangered Species Act.

7. 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 impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Teresa Heron is responsible for reviewing the application, and preparing the draft permit. She may be contacted at teresa.heron@dep.state.fl.us and 850-921-9529. Alvaro Linero is the project engineer responsible for preparing the draft BACT determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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PERMITTEE:

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

FPL West County Energy Center
DEP File No. 0990646-001-AC
Permit No. PSD-FL-354
SIC No. 4911
Expires: December 31, 2009

PROJECT AND LOCATION

This permit authorizes the construction of two nominal 1,250 megawatt combined cycle units at the proposed Florida Power and Light Company (FPL) West County Energy Center.

The proposed project will be located at 4000 205th Street, North, in unincorporated Palm Beach County. This site encompasses 220 acres of which approximately 40 acres will be used for two combined cycle units.

UTM coordinates are Zone 17; 562.19 km E; 2953.04 km N.

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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Michael G. Cooke, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The FPL West County Energy Center will be a nominal 2,500 megawatt (MW) greenfield power plant. The initial phase is the construction of two nominal 1,250 MW gas-fired combined cycle units that will use ultralow sulfur (ULS) fuel oil as backup fuel. The two combined cycle units are designated as Unit 1 and Unit 2.

Each combined cycle unit will consist of: three nominal 250 megawatt Model 501G gas turbine-electrical generator sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; one nominal 428 mmBtu/hour (LHV) gas-fired duct burner located within each of the three HRSG's; three 149 feet exhaust stacks; one 24- cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.

Additional ancillary equipment will include: four emergency generators; two natural gas fired fuel heaters; two diesel fuel storage tanks; two auxiliary steam boilers; and other associated support equipment.

{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}

NEW EMISSIONS UNITS

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

ID	Emission Unit Description
001	Unit 1A – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
002	Unit 1B – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
003	Unit 1C – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
004	Unit 2A – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
005	Unit 2B – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
006	Unit 2C – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator
007	Two nominal 6.3 million distillate fuel oil storage tanks*
008	Two 26 cell mechanical draft cooling towers
009	Two nominal 85,000 lb/hr (99.8 MMBtu/hr) auxiliary boilers
010	Two nominal 10 MMBtu/hr gas-fired process heaters
011	Four nominal 2,250 KW (~ 21 MMBtu/hr) emergency generators
012	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank

* This capacity will allow approximately 108 hours of on-site oil storage

REGULATORY CLASSIFICATION

Title III: This facility will be major for hazardous air pollutants (HAPs).

Title IV: The facility will operate emissions units 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 62-213, 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 facility is located in an area designated as "attainment," "maintenance," 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 PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: This project is subject to applicable requirements of 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed 40 CFR 60, NSPS-Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the facility will be subject to Subpart KKKK, and may no longer be subject to Subparts GG and Da. This project is also subject to applicable requirements of 40 CFR 60, NSPS-Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced After July 23, 1984); to 40 CFR 60, NSPS-Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) and to 40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ICE); Proposed Rule- Federal Register / Vol. 70, No. 131 / July 11, 2005.

NESHAPs: This project is subject to applicable requirements of 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. This project is also subject to applicable requirements of 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Reciprocating Internal Combustion Engines (RICE); and to 40 CFR 63, Subpart DDDDD National Emissions Standards for Industrial, Commercial, or Institutional Boilers and Process Heaters.

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

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Regulation Southeast District office (DEP-SED), 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Subparts A from NSPS 40 CFR 60 and NESHAP 40 CFR63; Identification of General Provisions.

Appendix BD: Final BACT Determinations and Emissions Standards.

Appendix Da: NSPS Requirements for Duct Burners, 40 CFR 60, Subpart Da.

Appendix Dc: NSPS Requirements for Small Steam Generating Units, 40 CFR 60, Subpart Dc.

Appendix DDDDD: NESHAP Requirements for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD.

Appendix GC: General Conditions.

Appendix GG: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart GG.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix YYYY: NESHAP Requirements for Gas Turbines, 40 CFR 63, Subpart YYYY.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

The following 40 CFR 60, New Source Standard Performance (NSPS) subparts, shall become part of this permit on the effective final date of each regulation:

Standards of Performance (NSPS) for Stationary Compression Ignition Internal Combustion Engines (ICE), 40 CFR 60, Subpart IIII; Proposed Rule (published July 11, 2005). This subpart will be eventually incorporated as Appendix IIII.

Standards of Performance (NSPS) for Stationary Gas Turbines, 40 CFR 60 Subpart KKKK; Proposed Rules (published February 18, 2004). This subpart will be eventually incorporated as Appendix KKKK.

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 April 14, 2005;
- Department PSD Application Sufficiency comments dated June 13, 2005;
- Sufficiency Responses received August 12, 2005;
- Draft permit package issued on March 1, 2006;
- Final Certification by the Power Plant Siting Board on Month Day, Year; and
- Final Determination distributed concurrently with Final PSD Permit.

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

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 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, 63, 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. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

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

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

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

7. Application for Title V Permit: The permittee shall submit an application, pursuant to Chapter 62-213, F.A.C, for a Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

A. COMBINED CYCLE UNITS 1 AND 2 – GAS TURBINES (EUs 001, 002, 003, 004, 005, and 006)

This section of the permit addresses the following emissions units.

Combined Cycle Units 1 and 2 and associated equipment

Description: Emissions units 001, 002, 003, 004, 005, and 006. Each emission unit consists of: a Model 501G combustion gas turbine-electrical generator set with automated gas turbine control, inlet air filtration system and evaporative cooling, a gas-fired heat recovery steam generator (HRSG) with duct burner, a HRSG stack, and associated support equipment. Each combined cycle unit is comprised of three of the described emission units. The project also includes two steam turbine-electrical generators, each of which serves a combined cycle unit.

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

Generating Capacity: Each of the six gas turbine-electrical generator sets has a nominal generating capacity of 250 MW. Each of the two steam turbine-electrical generators has a nominal generating capacity of 500 MW. The total nominal generating capacity of each of the "3 on 1" combined cycle unit is approximately 1,250 MW. The total nominal generating capacity of the proposed project is 2,500 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry Low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system further reduces NO_X emissions.

Stack Parameters: Each HRSG has a stack at least 149 feet tall with a nominal diameter of 22 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics without the duct burners:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	2,333 MMBtu/hour	59° F	195° F	1,330,197
Oil	2,117 MMBtu/hour	59° F	293° F	1,533,502

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

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The combustion turbines shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards for Subpart Da, Subpart GG, and Subpart KKKK (as proposed). Some separate reporting and monitoring may be required by the individual subparts.

   a *Subpart A, General Provisions*, including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests

- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

b *Subpart Da, Standards of Performance for Electric Utility Steam Generating Units:* These provisions include standards for duct burners.

c *Subpart GG, Standards of Performance for Stationary Gas Turbines:* These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

d *Subpart KKKK, Standards of Performance for Stationary Gas Turbines:* These provisions were published February 18, 2004 as a proposed new NSPS standard. The final rule will be applicable to Unit 001 through Unit 006 at the time of publication in the Federal Register. When the rule becomes final, Unit 001 through Unit 006 gas turbines may no longer be subject to NSPS Subparts Da and GG.

3. NESHAP Requirements: The combustion turbines are subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY and Appendix A, NESHAP Subpart A of this permit).

EQUIPMENT AND CONTROL TECHNOLOGY

4. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain six Model 501G gas turbine-electrical generator sets each with a generating capacity of 250 MW. Each gas turbine shall include an automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize DLN combustors. [Application; Design]

5. HRSGs: The permittee is authorized to install, operate, and maintain six new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the six gas turbines (1A to 1C and 2A to 2C) and deliver steam to one of the two steam turbine electrical generators. Each HRSG may be equipped with a gas-fired duct burner having a nominal heat input rate of 428 MMBtu per hour (LHV).

6. Gas Turbine/Supplementary-fired HRSG Emission Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN system to control NO_X emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

d. *Oxidation Catalyst*: The permittee shall design and build the project to facilitate possible future installation of oxidation catalyst system to control CO emissions from each gas combustion turbine/supplementary-fired heat recovery steam generator. The permittee may install oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 12.h.

e. *Ammonia Storage:* In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

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

PERFORMANCE RESTRICTIONS

7. Permitted Capacity - Gas Turbines: The nominal heat input rate to each gas turbine is 2,333 MMBtu per hour when firing natural gas and 2,117 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

8. Permitted Capacity - HRSG Duct Burners: The total nominal heat input rate to the duct burners for each HRSG is 428 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

9. Authorized Fuels: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. The gas turbine shall fire no more than 500 hours of fuel oil, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. Hours of Operation: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

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

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

    b. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.

c. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all six HRSGs) shall not exceed 7,395,840 MMBtu (LHV) during any consecutive 12 months.

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

EMISSIONS STANDARDS

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

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	42.0	8.0, 24-hr 6, 12-month [h]
	Gas	CT & Duct Burner (DB)	7.6	52.5	
		CT Normal	4.1	23.2	
NO_X [b]	Oil	CT	8.0	82.4	8.0, 24-hr
	Gas	CT & DB	2.0	24.2	2.0, 24-hr
		CT Normal	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC [e]	Oil	CT	6.0	19.6	NA
	Gas	CT & DB	1.5	5.4	
		CT Normal	1.2	4.1	
Ammonia [f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner modes. The stacks test limits apply only at high load (90-100% of the combustion turbine capacity).

b. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the combustion turbine capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any combustion turbine/supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

{"DB" means duct burning. "SCR" means selective catalytic reduction. "NA" means not applicable}.

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

13. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da.

{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da} [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

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

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

16. Definitions

a. *Startup* is defined as 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.
[Rule 62-210.200(245), F.A.C.]

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
[Rule 62-210.200(230), F.A.C.]

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

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

18. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed eight hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

c. *Gas Turbine/HRSG System Cold Startup*: For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. *Fuel Switching*: For fuel switching, excess emissions shall not exceed 2 hour in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines.
[Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

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

EMISSIONS PERFORMANCE TESTING

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

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

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

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

23. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

24. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall

be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

    b. *NO_X Monitors.* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEM Data Requirements:

    a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

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

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 17 and 18 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

[NSPS Subparts Da and 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; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

RECORDS AND REPORTS

28. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system 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.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test

results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day 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.

b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority. This also includes reporting any periods of excess emissions as applicable and defined by NSPS Subpart KKKK when the rule is finalized.

{Note: If there are no periods of excess emissions as defined in NSPS Subparts GG, Da, or KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. DISTILLATE FUEL OIL STORAGE TANK (EU 007)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
007	Two Nominal 6.3 million gallon distillate fuel oil storage tanks

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

   The listed emission units shall comply with 40 CFR 60, Subpart Kb only to the extent that the regulations apply to the emission unit and its operations.

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain two 6.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

C. COOLING TOWER (EU 008)

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

ID	Emission Unit Description
008	Two 26-cell mechanical draft cooling towers

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install two new 24-cell mechanical draft cooling towers with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

DRAFT

D. AUXILIARY BOILERS AND PROCESS HEATERS (EU009 – EU 010)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
009	Two limited use gas-fueled auxiliary boilers (99.8 MMBTU/h and 85,000 lb/hr)
010	Two gas-fueled 10 MMBtu/hr process heaters

NESHAP APPLICABILITY

1. NESHAP Subpart DDDDD Applicability: These emissions units are subject to Subpart DDDDD, which applies to an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 40 CFR 63.2.

   The listed emission units shall comply with 40 CFR 63, NESHAP Subpart DDDDD only to the extent that the regulations apply to the emission unit and its operations (e.g. limited use gas-fueled or small gas-fueled categories.

   [40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater]

NSPS APPLICABILITY

2. NSPS Subpart Dc Applicability: Each 99.8 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].

EMISSIONS AND TESTING REQUIREMENTS

3. Auxiliary Boiler BACT Emissions Limits:

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.05 lb/MMBtu	0.08 lb/MMBtu	2 gr S/100SCF natural gas spec and 10% Opacity

4. Auxiliary Boilers Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 63.7]

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

5. Annual CO Performance Test for Auxiliary Boilers: Pursuant to 40 CFR 63.7515(e) permittee shall conduct an annual CO test according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

   [40 CFR 63.7515 and Rule 62-204.800(11)(b)84. F.A.C.]

6. Natural Gas Fired Process Heaters BACT Emissions Limits:

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.095 lb/MMBtu	0.08 lb/MMBtu	2 gr S/100SCF natural gas spec and 10% Opacity

7. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

EQUIPMENT SPECIFICATIONS

8. Equipment: The permittee is authorized to install, operate, and maintain two auxiliary boilers with a maximum design heat input of 99.8 MMBtu/hr (85,000 lb/hr) each to produce steam during start up of the CTs and two 10 MMBtu/hr process heaters for the purpose of heating the natural gas supply to the CTs. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

9. Hours of Operation: The hours of operation of each limited use gas-fueled auxiliary boiler shall not exceed 500 hours per year. The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C. and 40 CFR 63.7575]

NOTIFICATION, REPORTING AND RECORDS

10. Notification: Initial notification is required for the two limited use 99.8 MMBtu/hr gas-fueled auxiliary boilers. Initial notification is not required for the two small gas-fueled 10 MMBtu/hr process heaters. [40 CFR 63.9, 40 CFR 63.7506(c) and Rule 62-204.800(11)(b) F.A.C.]

11. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters and auxiliary boilers. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

EMERGENCY GENERATOR (011)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
011	Four 2,250 Kw Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines

NESHAPS APPLICABILITY

1. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and are subject to 40 CFR 63, Subpart ZZZZ. They shall comply with 40 CFR 63, NESHAP Subpart ZZZZ only to the extent that the regulations apply to the emissions unit and its operations.

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and are subject to 40 CFR 60, Subpart IIII. They shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emission unit and its operations (e.g. non-road, emergency, displacement, capacity, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register Vol. 70, No. 131, July 11, 2005. Pages 39869 – 39904].

EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain four 2,250 Kw emergency generators. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per each generator. The generators are allowed to burn 0.0015% sulfur fuel oil.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Emergency Generators BACT Emissions Limits:

NO_X	CO	Hydrocarbons[1]	SO_2	PM/PM_{10}
6.9 gm/bhp-hr	8.5 gm/bhp-hr	1.0 gm/bhp-hr	0.0015% S F.O.	0.4 gm/bhp-hr

   Note 1. Hydrocarbons are surrogate for VOC.

   {The Draft BACT limits are equal to the values corresponding to the Tier 1 values cited in the proposed rule 40 CFR 60, Subpart IIII. The Final BACT will be revised to comport with the final rule when issued.}

6. Emergency Generators Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, an EPA Certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values and the use of ULS fuel oil can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4211]

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

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

7. Notifications: Initial notification are required pursuant to 40 CFR 60.7, 40 CFR 63.9, and 40 CFR 63.6590 (b) (i) for the four 2,250 Kw RICE units.
8. Reporting: The permittee shall maintain records of the amount of liquid fuel used. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3) F.A.C.].

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank.

NESHAP APPLICABILITY

1. NESHAP Subpart ZZZZ Applicability: This unit consists of one or more Emergency Fire Pump Engines that are also Liquid Fueled Reciprocating Internal Combustion Engines (RICE), subject to 40 CFR 63, Subpart ZZZZ. They shall comply with 40 CFR 63, NESHAP Subpart ZZZZ only to the extent that the regulations apply to the emission unit and its operations (e.g. Limited Use, Emergency Fire Pumps).

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: These fire pumps engines are Emergency Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and are subject to 40 CFR 60, Subpart IIII. They shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register, Vol. 70, No. 131, July 11, 2005. Pages 39869 – 39904].

EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) and an associated 500 gallon fuel oil storage tank.

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation: The fire pump may operate in response to emergency conditions and 40 non-emergency hours per year for maintenance testing.
   [Applicant Request; Rule 62-210.200 (PTE), F.A.C.

5. Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

   Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

6. Fire Pump Engine BACT Emissions Limits:

The following limits apply based on the size category of fire pumps located at the facility.

Size (hp)	**CO**	**NMHC+NO_X**	**PM**
175 and greater	2.6	7.8	0.40

Note 1. Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

{The Draft BACT limits are equal to the values corresponding to the respective size class indicated above and cited in the proposed rule 40 CFR 60, Subpart IIII. The Final BACT will be revised to comport with the final rule when issued.}

7. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.411]

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NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

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§ 60.5 Determination of construction or modification.

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Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

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NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

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§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

DRAFT BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	42.0	8.0, 24-hr 6, 12-month [h]
	Gas	CT & Duct Burner (DB)	7.6	52.5	
		CT Normal	4.1	23.2	
NO_X [b]	Oil	CT	8.0	82.4	8.0, 24-hr
	Gas	CT & DB	2.0	24.2	2.0, 24-hr
		CT Normal	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC [e]	Oil	CT	6.0	19.6	NA
	Gas	CT & DB	1.5	5.4	
		CT Normal	1.2	4.1	
Ammonia [f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner modes. The stacks test limits apply only at high load (90-100% of the combustion turbine capacity).

b. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the combustion turbine capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any combustion turbine/supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: Approved By:

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Michael G. Cooke, Director
Division of Air Resources Management

Date

Date

A 99.8 MMBTu/hr (85,000 lb/hr) auxiliary boiler will serve each combined cycle unit system to produce steam during start up of the CTs. They are regulated as Emissions Unit 009. The provisions of this Subpart may be provided in full upon request.

{Note: Only applicable definitions have been included.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

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

(3) 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.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Units 1 and 2 gas turbine/HRSG systems, which are regulated as Emissions Units 001, 002, 003, 004, 005, and 006. The provisions of this Subpart may be provided in full upon request.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

"Duct burner" means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Gross output" means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM_{10} emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil (≤ 0.05% sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_X) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h) \qquad \text{(Equation 1)}$$

Where:

E = Emission rate of NOx from the duct burner, ng/J (lb/Mwh) gross output

Csg = Average hourly concentration of NO_X exiting the steam generating unit, ng/ dscm (lb/dscf)

Cte = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = Average hourly gross energy output from steam generating unit, J (Mwh)

h = Average hourly fraction of the total heat input to the steam generating unit de-rived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_X concentrations (Csg and Cte). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NOx limits established in the PSD permit shall demonstrate compliance with NO_X limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_X standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_X emission rate when demonstrating compliance with the NO_X standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

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

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

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The gas turbines are regulated as Emissions Units 001, 002, 003, 004, 005, and 006. The provisions of this Subpart may be provided in full upon request.

§ 60.330 Applicability and Designation of Affected Facility.

Each unit has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

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

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

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

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

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

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

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

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

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_X) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

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

Where:

STD = Allowable NO_X 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 = NO_X emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_X contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_X emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NOx standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil (≤ 0.05% sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_X standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_X emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_X) for each run using the following equation:

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

Where:

NOx	=	Emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent
NOxo	=	Observed NOx concentration, ppm by volume
Pr	=	Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
Po	=	Observed combustor inlet absolute pressure at test, mm Hg
Ho	=	Observed humidity of ambient air, g H_2O/g air
e	=	Transcendental constant, 2.718
Ta	=	Ambient temperature, °K

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the specified NO_X limits. The permittee is allowed to make the initial compliance demonstration for NO_X emissions using certified CEMS data, provided that compliance is 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 NO_X monitor. The permittee is not required to have the NO_X monitor continuously correct NO_X emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

STANDARD CONDITIONS

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

EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

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

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

TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

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

RECORDS AND REPORTS

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

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

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

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

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

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

Reporting period dates: From ______________________ to _________________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: __________________________

Process Unit(s) Description: ____

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

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

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

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

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

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

Name: ____

Signature: ____ *Date*: ____________________

Title: ____

The gas turbines are subject to the applicable requirements of this 40 CFR 63, Subpart YYYY. The provisions of this Subpart may be provided in full upon request. The gas turbines are regulated as Emissions Units 001, 002, 003, 004, 005, and 006.

Applicability of NESHAP Subpart YYYY

The West County Energy Center will be a major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the West County Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

The auxiliary boilers and process heaters are subject to the applicable requirements of this 40 CFR 63, Subpart DDDDD. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register Dated 9/12/04

What This Subpart Covers
63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards
63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

General Compliance Requirements
63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

Testing, Fuel Analyses, and Initial Compliance Requirements
63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

Continuous Compliance Requirements
63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

Notifications, Reports, and Records
63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

Other Requirements and Information
63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63
Table 1 to Subpart DDDDD of Part 63--Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63--Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63--Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63--Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63--Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63--Reporting Requirements
Table 10 to Subpart DDDDD of Part 63--Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD
Appendix A to Subpart DDDDD--Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B to Subpart DDDDD--Applicability of General Provisions to Subpart DDDDD

The emergency generators and fired pump are subject to the applicable requirements of this 40 CFR 63, Subpart ZZZZ. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register dated 6/15/04; Effective Date 8/16/04

What This Subpart Covers
63.6580 The purpose of subpart ZZZZ
63.6585 Subject to this subpart
63.6590 Parts of my plant does this subpart cover
63.6595 Compliance with this subpart

Emission Limitations
63.6600 Emission limitations and operating limitations

General Compliance Requirements
63.6605 General requirements for complying with this subpart

Testing and Initial Compliance Requirements
63.6610 Dates to conduct the initial performance tests or other initial compliance demonstrations
63.6615 Subsequent performance tests
63.6620 Performance tests and other procedures
63.6625 Monitoring, installation, operation, and maintenance requirements
63.6630 Initial compliance with the emission limitations and operating limitations

Continuous Compliance Requirements
63.6635 Monitoring and collecting data to demonstrate continuous compliance
63.6640 Continuous compliance with the emission limitations and operating limitations

Notification, Reports, and Records
63.6645 Notifications
63.6650 Reports
63.6655 Records
63.6660 Records form and retention

Other Requirements and Information
63.6665 General Provisions
63.6670 implementation and enforcement
63.6675 Definitions

Tables to Subpart ZZZZ of Part 63
Table 1a to Subpart ZZZZ of Part 63--Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE
Table 1b to Subpart ZZZZ of Part 63--Operating Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE
Table 2a to Subpart ZZZZ of Part 63--Emission Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE

Table 2b to Subpart ZZZZ of Part 63--Operating Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE
Table 3 to Subpart ZZZZ of Part 63--Subsequent Performance Tests
Table 4 to Subpart ZZZZ of Part 63--Requirements for Performance Tests
Table 5 to Subpart ZZZZ of Part 63--Initial Compliance with Emission Limitations and Operating Limitations
Table 6 to Subpart ZZZZ of Part 63--Continuous Compliance with Emission Limitations and Operating Limitations
Table 7 to Subpart ZZZZ of Part 63--Requirements for Reports
Table 8 to Subpart ZZZZ of Part 63--Applicability of General Provisions to Subpart ZZZZ- See Appendix A to Subpart ZZZZ

Appendix A to Subpart ZZZZ of Part 63- Applicability of General Provisions to Subpart ZZZZ

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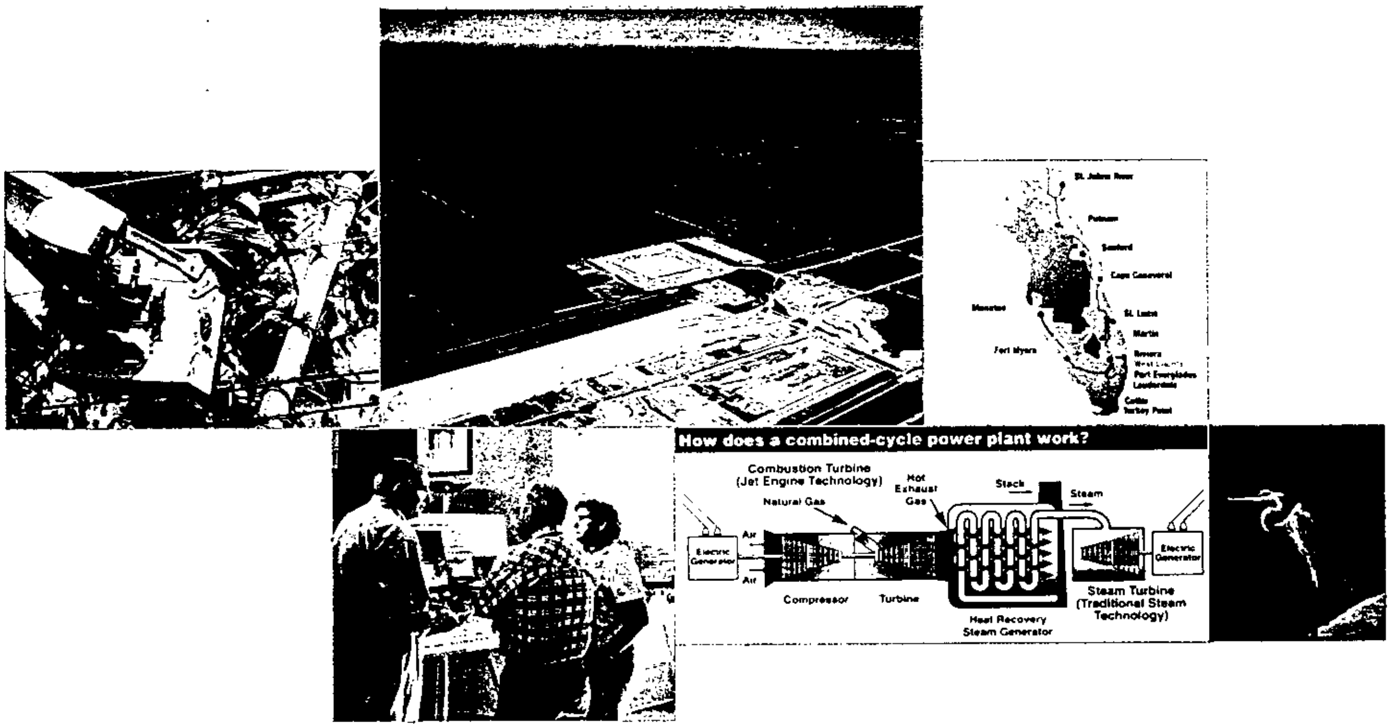

Air Construction/PSD Permit Application Sufficiency Information

FPL