FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 7, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. A. K. Sharma, P.E.
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Re: DEP File No. PSD-FL-254 (PA98-38)
Cane Island Power Park Unit 3
250 Megawatt Combined Cycle Combustion Turbine

Dear Mr. Sharma:

Enclosed is one copy of the Draft PSD Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the referenced project at Cane Island Power Park located at 6075 Old Tampa Highway, near Intercession City, Osceola County. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" must be published as soon as possible in a newspaper of general circulation in the area affected. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit. The final PSD permit will not be issued prior to approval of the project by the Siting Board.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Ms. Teresa Heron at 850/921-9529.

Sincerely,

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

CHF/aal

Enclosures

In the Matter of an
Application for Permit by:

Mr. A. K. Sharma, Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Facility I.D. No. 0970043
DRAFT Permit No.: PSD-FL-254
Cane Island Power Park Unit 3
Osceola County

_______________________________/

INTENT TO ISSUE PSD PERMIT

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 (copy of Draft PSD Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, The Kissimmee Utility Authority, applied on August 5, 1998 to the Department for a PSD permit to construct a 250 megawatt combined cycle unit consisting of: a nominal 167 MW combustion turbine-electrical generator; a supplementally-fired heat recovery heat generator capable of raising sufficient steam to generate another 80-90 MW from a steam-electrical generator; a 1.0 million gallon fuel oil storage tank, and two stacks at the Cane Island Power Park, located at 6075 Old Tampa Highway, near Intercession City, Osceola County.

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

The Department intends to issue this PSD 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. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed ""Public Notice of Intent to Issue PSD Permit." The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. 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). The Department suggests that you publish the notice within thirty days of receipt of this letter. 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 or other authorization. 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 a public hearing (meeting) concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue PSD Permit." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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).

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

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

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

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.

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1-7-99 to the person(s) listed:

Mr. A. K. Sharma, KUA*
Mr. Jeff Ling, KUA
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, DEP CD
Mr. Buck Oven, DEP PPSO
Mr. D. D. Schultz, P.E., Black & Veatch

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.

Kim Tober 1-7-99
(Clerk) (Date)

Z 333 612 586

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to: AK Sharma	
Street & Number: KUA	
Post Office, State, & ZIP Code: Kissimmee, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: 1-7-99 P50-Fl-254 PA 98-38 CI PP Unit 3	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. A.K. Sharma, PE
Kissimmee Utility Auth.
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

4a. Article Number
Z 333 612 586

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

7. Date of Delivery
1/11/99

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X Manuel [illegible]

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

Thank you for using Return Receipt Service.

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-254

Kissimmee Utility Authority
Cane Island Power Park Unit No. 3
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to The Kissimmee Utility Authority (KUA). The permit is to construct: a nominal 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine with a heat recovery steam generator and supplemental duct burners; a 1.0 million gallon fuel oil storage tank; a 130-foot main stack; and a 100 foot bypass stack at the Cane Island Power Park at 6075 Old Tampa Highway, Osceola County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are The Kissimmee Utility Authority, 1701 West Carroll Street, Kissimmee, Florida 34741-6804.

The new unit will be a General Electric PG7241FA combustion turbine-electrical generator which will generate 167 MW (nominal) in simple cycle mode or 250 MW in combined cycle mode. The unit will operate primarily on natural gas and will be permitted to operate 8760 hours per year of which no more than 720 will be on 0.05 percent sulfur distillate fuel oil. The supplemental duct burners will operate only during high ambient temperature and will partially compensate for lower power capacity achievable at high temperature.

NO_X emissions will be controlled by Dry Low NO_X (DLN) combustors capable of achieving emissions of 9 parts per million by volume at 15 percent oxygen. Lower emission limits will apply if the KUA chooses selective catalytic reduction in lieu of or in conjunction with DLN technology. NO_X will be controlled under the minimal back-up fuel oil operation by water or steam injection. SO_2 and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC will be controlled by good combustion practices. Emissions of CO will be similarly controlled unless the KUA chooses to install an oxidation catalyst.

The maximum emissions in tons per year based on the original application and prior to final selection of the combustion turbine are summarized below. NO_X, VOC, and CO emissions will be substantially lower as a result of the emissions characteristics of the GE combustion turbine selected since receipt of the application and the Department's proposed BACT determination.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	109	25/15
SO_2	38	40
NO_X	823	40
VOC	173	40
CO	3818	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

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

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).

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

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

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

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.

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

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

Dept. Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-5963

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741-6804
Telephone: 407/933-7777
Fax: 407/847-0787

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

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Kissimmee Utilities Authority

Cane Island Power Park Unit 3

250 Megawatt Combined Cycle Unit

Intercession City, Osceola County

Facility I.D. No. 0970043

PSD-FL-254, PA98-38

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

January 7, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Kissimmee Utility Authority (KUA)
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Authorized Representative: Mr. A. K. Sharma, Director of Power Supply

1.2 Reviewing and Process Schedule

08-05-98: Date of Receipt of Application
08-17-98: Preliminary DEP/BAR Incompleteness Letter
10-08-98: Department Statement of Sufficiency (Not Sufficient)
11-06-98: KUA Response to Statement of Sufficiency
01-07-99: Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The Cane Island Power Park is located at 6075 Old Tampa Highway, near Intercession City, Osceola County. This site is approximately 105 kilometers from the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates of this facility are Zone 17; 447.72 km E; 3127.68 km N.

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

This facility presently generates electric power from one 40 megawatt (MW) simple cycle combustion turbine and one 120 MW combined cycle unit including a heat recovery steam generator (HRSG). Both existing units fire natural gas as the primary fuel, with distillate fuel as backup.

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

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

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
003	Power Generation	One nominal 167 Megawatt (nominal) Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1.0 Million Gallon Fuel Oil Storage Tank
005	Steam Generation	One 44 mmBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator (and 80-90 MW Steam Electrical Turbine)
006	Water Cooling	Cooling Tower

The Kissimmee Utility Authority (KUA) proposes to construct a nominal 250 megawatt (MW) combined cycle combustion turbine (Unit 3) at the existing Cane Island Power Park located at 6075 Old Tampa Highway near Intercession City in Osceola County. The project includes: a nominal 167 MW General Electric PG7241FA combustion turbine-electrical generator operating primarily on natural gas; 44 million Btu per hour (mmBtu/hr) supplementally-fired heat recovery steam generator (HRSG); an 80-90 MW (gross output) steam turbine; two stacks; a fuel oil storage tank; and ancillary equipment. KUA wishes to maintain flexibility to operate the unit in simple cycle mode.

The turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors for the control of NO_X emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. The turbine will have a nominal heat input rating of 1,696 mmBtu/hr lower heat value (LHV) at 19 °F while operating at 100% load.

The duct burner will have a design fuel input capacity of 44 mmBtu/hr higher heating value (HHV). The purpose of this relatively small duct burner is to partially compensate for the loss of output from the combustion turbine (which can be on the order of 20 MW) at high ambient temperatures. The duct burner will be of a "Low NO_X" design in order to control emissions of nitrogen oxides.

The main fuel will be natural gas and the unit will operate up to 8760 hours per year, of which no more than 720 represent fuel oil operation. Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). Emission increases of SO_2, and H_2SO_4 will be less than their respective significant emission levels per Table 62-212.400-2, F.A.C. and do not require PSD or non-attainment new source review. PSD review is required for CO, PM/PM_{10}, NO_X, and VOC since emissions, per the application, will increase by more than their respective significant emissions levels.

At low temperature and full load, enough steam can be raised to generate 80-90 MW from the steam turbine without supplemental firing. The firing capability will partially compensate for the lower heat input from the combustion turbine to the HRSG during periods of high ambient (compressor inlet) temperatures.

Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). Emission increases of SO_2, and H_2SO_4 will be less than their respective significant emission levels per Table 62-212.400-2, F.A.C. and do not require PSD or non-attainment new source review. PSD review is required for CO, PM/PM_{10}, NO_X, and VOC since emissions, per the application, will increase by more than their respective significant emissions levels.

4. PROCESS DESCRIPTION

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

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

An exterior view of the GE MS 7001FA (a predecessor of the PG 7241FA) is shown in Figure 1. The key components are identified in Figure 2. The unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of those shown in Figure 2.

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

In the KUA project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine which also drives an electrical generator. Figure 3 is a process flow diagram for combined cycle operation. The bypass stack is used when the unit operates in simple cycle mode. The main stack following the HRSG is required for combined cycle operation.

Because the HRSG will be equipped with a duct burner, the hot combustion turbine exhaust gases (containing a high excess air fraction) can be used as combustion air to raise additional steam by supporting the combustion of additional gas. Figure 4 is a diagram of an in-line duct burner manufactured by Coen.

KUA expects to operate the unit in simple cycle mode during periods when the HRSG is not operational or when electrical demand makes it uneconomical to operate the HRSG. In simple cycle mode, the thermal efficiency of the GE 7FA line of combustion turbines is about 35 percent. In combined cycle mode, with steam used to generate electrical power, efficiencies of 56 percent are possible (higher with the duct burner in operation).

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an evaporative chiller may be installed ahead of the combustion turbine inlet. At an ambient temperature of 102 ^{o}F, roughly 10 MW of power can be regained by using the chillers. The duct burner may also be used at high temperature to raise additional steam. The heat input from firing the duct burners will be approximately 2-4 percent (less than 100 mmBtu per hour) of the total heat input to the combustion turbine.

The project includes highly automated controls, described as the GE Mark V Control System. The SPEEDTRONIC Mark V Gas Turbine Control System is designed to fulfill all of the gas turbine control requirements.

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

5. RULE APPLICABILITY

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

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

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, VOC, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth. This project will also be reviewed for Site Certification under the Power Plant Siting Act.

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

5.1 State Regulations

Chapter 62-17	Electrical Power Siting
Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

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

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, and negligible quantities of sulfuric acid mist, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 24 through 29 of Draft Permit PSD-FL-254.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutants	Gas Firing[2]	Oil Firing[3]	Total[1]	PSD Significance	PSD REVIEW?
PM/PM_{10}	81	41	109	25	Yes
SO_2	4.5	37	38	40	No
NO_X	857	118	823	40	Yes
CO	3818	1047	3463	100	Yes
Ozone(VOC)	132	70	<100[4]	40	Yes
Sulfuric Acid Mist	<<7	<<7	<7	7	No
Mercury	<<0.1	<<0.1	<0.1	0.1	No
Lead	<<0.6	<<0.6	<0.6	0.6	No

1. Based on 8040 Hours of gas firing and 720 hours of fuel oil firing. Reference ambient temperature is 72 °F.
2. Based on 8760 hours of gas firing and assumes highest possible emissions over all temperatures, loads, etc.
3. Based on 720 hours of fuel oil firing and assumes highest possible emissions over all temperatures, loads, etc.
4. Emissions will be <100 because of the draft BACT determination and the actual characteristics of selected gas turbine. Estimate received from Black & Veatch on January 5, 1999 is actually < 40 TPY which would not trigger PSD.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean natural gas. The gas turbine combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The DLN-2.6 combustors will control combustion turbine emissions of CO and NO_X to 9 ppm @15% O_2 between 50 and 100% of full load under normal operating conditions. Low NO_X burners will be utilized in the HRSG to achieve NO_X values of 0.4 lb/MW-hr. Selective catalytic reduction (SCR) is available if these rates cannot be achieved by Low NO_X technologies. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, NO_X, and VOC. PM_{10} and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO and VOC are criteria pollutants and have only AAQS and significant impact levels defined for them. Since the project's VOC emissions increase is less than 100 tons per year no air quality analysis is required for VOC.

The applicant's initial PM_{10}, CO and NO_X air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. The nearest PSD Class I area is the Chassahowitzka National Wilderness Area located 105 km to the northwest. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

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

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 <u>Models and Meteorological Data Used in the Significant Impact Analysis</u>

The EPA-approved SCREEN3 (screening model) and Industrial Source Complex Short-Term (ISCST3) dispersion models were used to evaluate the pollutant emissions from the proposed project. These models determine ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. They incorporate elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Orlando, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments. Receptors were placed within 15 km of the facility, which is located in a PSD Class II area, and the Chassahowitzka National Wilderness Area (CNWA) which is a PSD Class I area located approximately 105 km to the northwest of the project at its closest point. The receptor grid for predicting maximum concentrations in the vicinity of the project was a nested rectangular receptor grid comprised of more than 1000 receptors. For predicting impacts at the CNWA, 13 discrete receptors along the border of the PSD Class I area were used. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the CNWA. The tables below show the results of this modeling.

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

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.06	1	NO
	24-hour	2.33	5	NO
CO	8-hour	178	500	NO
	1-hour	1421	2000	NO
NO_2	Annual	0.5	1	NO

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

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.003	0.2	NO
	24-hour	0.2	0.3	NO
NO_2	Annual	0.02	0.1	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plant 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 VOC as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels which in-turn are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and No. 2 fuel oil are clean fuels and produce contain little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species. A regional haze analysis was performed which shows that the proposed project will not result in adverse impacts on visibility in the PSD Class I area.

Growth-Related Air Quality Impacts

The applicant projects that there will be only short-term increases in the labor force to construct the project and that it will not result in permanent, significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require two more permanent employees which will cause no significant impact on the local area.

On a larger scale, the project was reviewed by the Public Service Commission, who determined that power projects are needed will help meet the low electrical reserves throughout the State of Florida. The project is a response to state-wide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has the smallest overall physical "footprint," the least water requirements, the lowest capital costs and the lowest air emissions per unit of electric power generating capacity.

Hazardous Air Pollutants

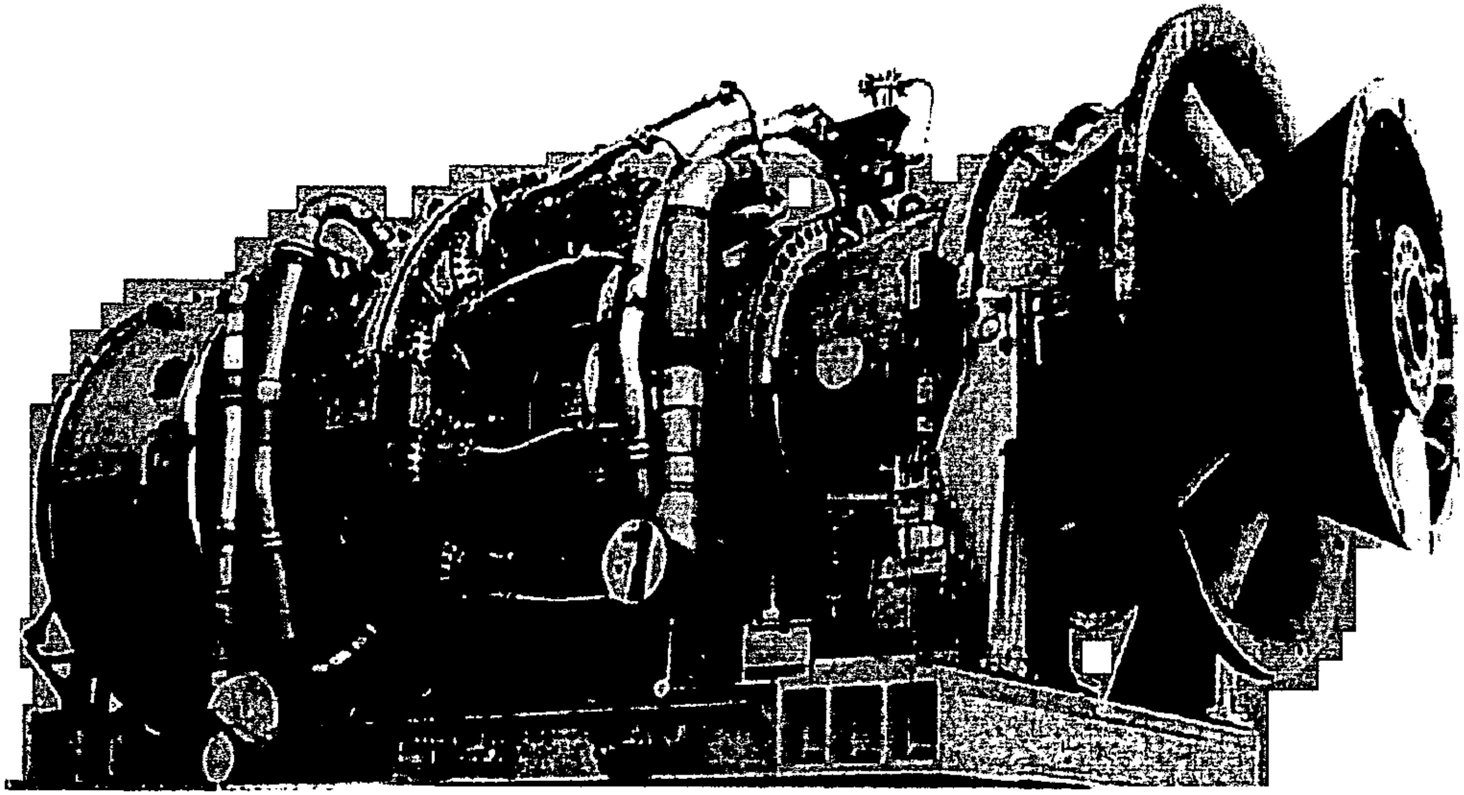
The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Sections 112 of the Clean Air Act.

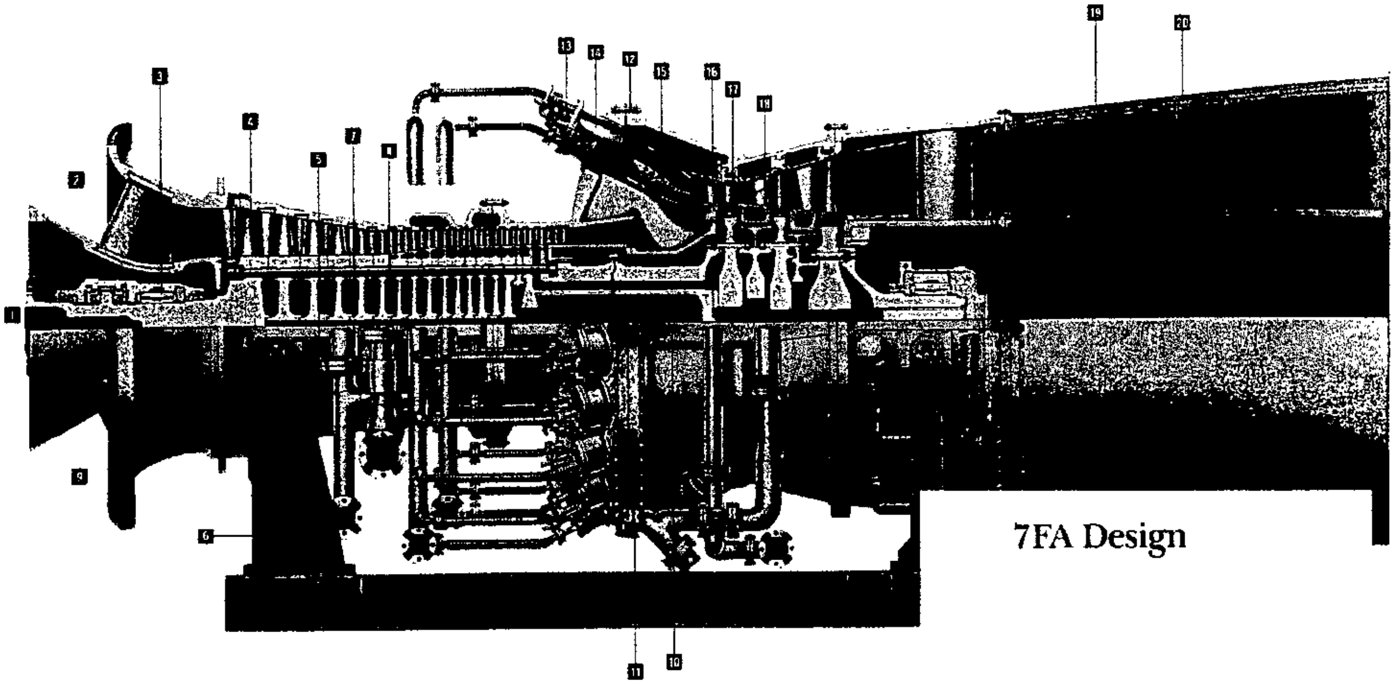
7. CONCLUSION

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

A. A. Linero, P.E.
Teresa Heron, Engineer
Cleve Holladay, Meteorlogist

Figure 1 - GE MS7001FA

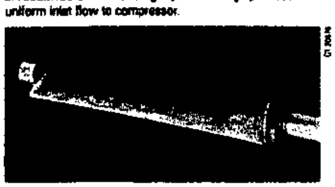




COMPRESSOR

1. Load Coupling – short, rigid coupling can be directly connected to generator flange

2. Axial/Radial Inlet Casing – proven design provides uniform inlet flow to compressor.



3. Journal Bearings – bearings are tilting-pad type for improved rotor stability and are also pressure-lift for reduced break-away torque.

4. Compressor Blading – an evolution from the 7EA compressor with a zero stage added. Blade length increased for added flow. Blade material upgraded for more demanding requirements. Shrouded stator 17 and exit guide vanes are utilized for improved cyclical life.

5. Compressor Design – based on proven axial-flow design. One piece casing allows easier start-up. Casing material upgraded to accommodate higher temperature and pressure.

6. Rigid Forward Support – in combination with forward thrust bearing, limits thermal expansion of gas turbine into generator.

7. Wheel Construction – machined to nearly constant stress cross-section with contact faces at maximum diameter for high rotor stiffness

8. Through-Bolt Construction – large bolts at maximum bolt circle provide rigid rotor with required torque capability for front-end drive.

9. Inlet Orientation – available in up, down or side arrangement

STATOR CASINGS

10. Horizontally Split – all casings split on horizontal centerline with through-bolting to facilitate maintenance

COMBUSTION

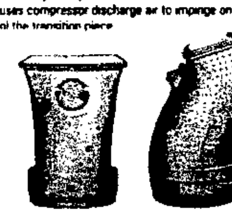
11. Combustor Bulkhead – combustor outer cans attached over elongated holes in combustor bulkhead to permit removal of transition piece without lifting turbine shell

12. Top and Bottom Manway Access – permits an alternative method for removing combustor transition piece and stage 1 nozzle without lifting turbine shell.

13. Fuel Distribution – single fuel line connection for each combustor with manifolding to six fuel nozzles built into combustor and cover.

14. Reverse Flow Combustor Chambers – supplement the impingement and film cooling of the liners, prolonging parts life.

15. Impingement Cooled Combustor Transition Piece – separate perforated sleeve around transition piece causes compressor discharge air to impinge on and effectively cool the transition piece



TURBINE

16. Nozzle Design – sidewalls and internal surfaces of vanes impingement cooled with spent air used for extensive film cooling

17. Stage 1 Stationary Shroud Design – gas path insert of high temperature alloy, extensively convection, impingement and film cooled and coated for maintaining tight clearances with the stage 1 bucket tip.

1st Stage *2nd Stage* *3rd Stage*

18. Bucket Design – stage 1 bucket is directionally solidified and uses a turbulated serpentine cooled design with trailing edge bleed cooling, based on GE Aircraft Engine technology. Stage 2 uses turbulated radial cooling holes. Stage 3 is uncooled. Stages 2 and 3 have integral z-lock shrouds for vibration control, and all three stages have long shanks for vibration control and isolation of gas path temperatures from the turbine wheels.

EXHAUST

19. Exhaust Diffuser – axial design (permitted by front-end drive) is blanket insulated for thermal stability, safety and reduced heat loss from exhaust before entering heat recovery system.

20. Exhaust Thermocouples – sets of thermocouples supply signals to each of the three SPEEDTRONIC™ Mark V computers. The thermocouples are used for control and also for monitoring the combustion system.

Figure 2 - GE Combustion Turbine MS 7001FA

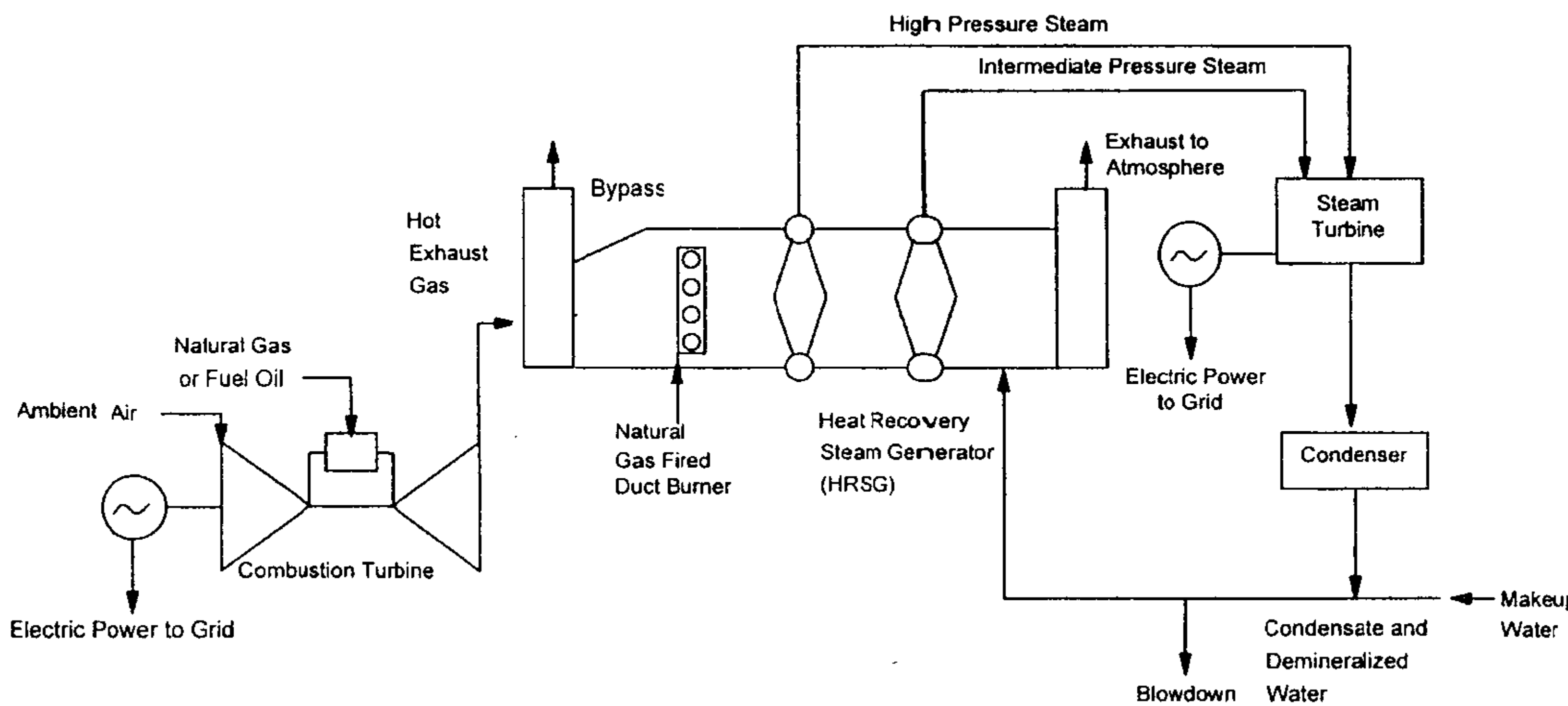


Figure 3 - Combined Cycle Process

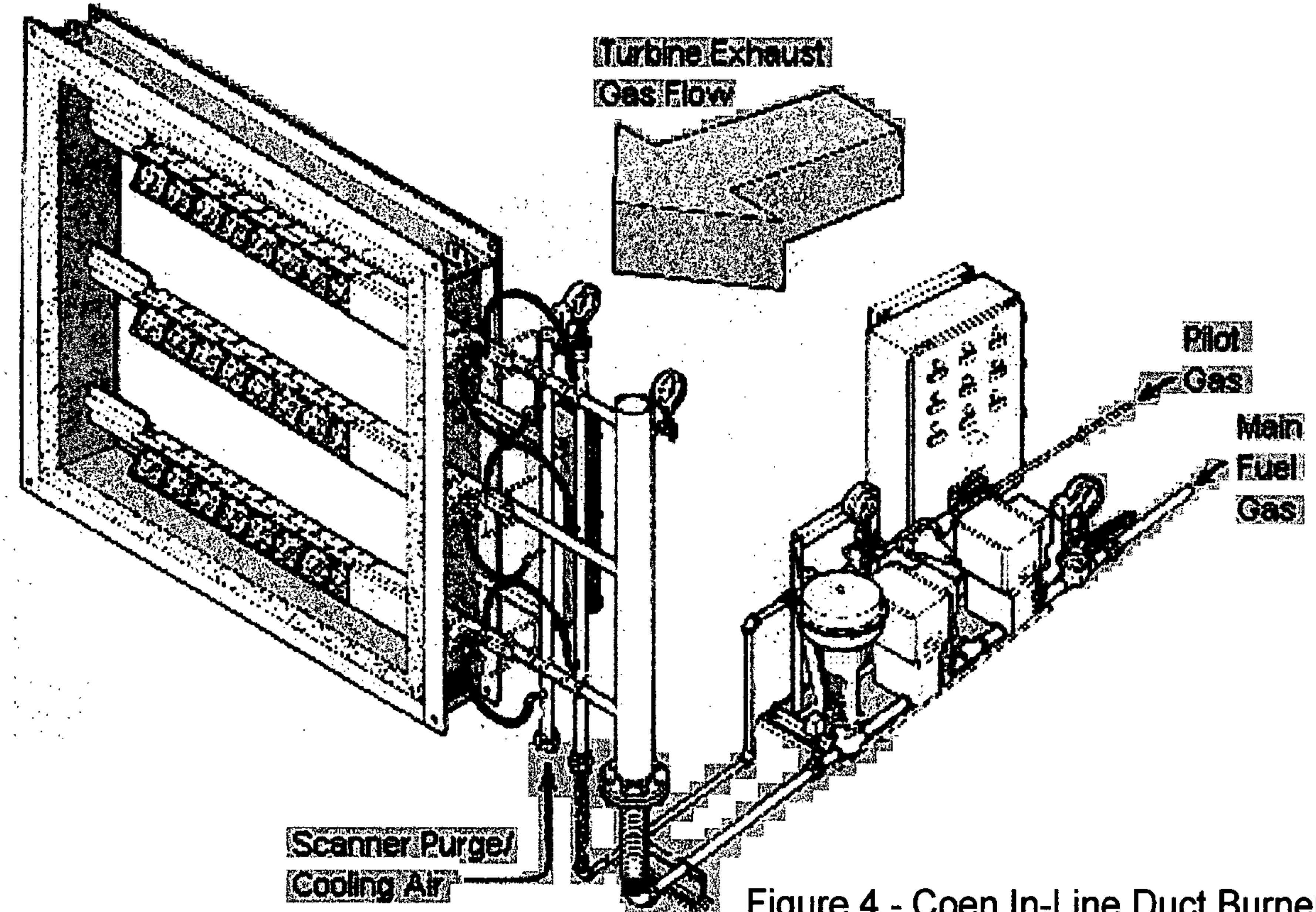


Figure 4 - Coen In-Line Duct Burner

PERMITTEE:

Kissimmee Utility Authority (KUA)
1701 West Carroll Street
Kissimmee, Florida 34741-6804

File No.	PSD-FL-254 (PA98-38)
FID No.	0970043
SIC No.	4911
Expires:	December 31, 2002

Authorized Representative:

A.K. Sharma, Director of Power Supply

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 167 megawatt (MW), gas-fired, stationary combustion turbine-electrical generator; a supplementally-fired heat recovery steam generator (HRSG); a nominal 80-90 MW steam electrical generator; a 1.0 million gallon storage tank for back-up distillate fuel oil; a 130 foot stack; and a 100-foot bypass stack for simple cycle operation. The unit will achieve approximately 250 megawatt in combined cycle operation at referenced conditions. The unit is designated as Unit 3 and will be located at the Cane Island Power Park, 6075 Old Tampa Highway, near Intercession City, Osceola County. UTM coordinates are: Zone 17; 447.72 km E; 3127.68 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility 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 of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-254

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The existing Kissimmee Utility Authority (KUA) Cane Island Power Park consists of a nominal 40 MW simple cycle combustion turbine designated as Unit 1 and a nominal 120 MW combined cycle combustion turbine-electrical generator with a heat recovery steam generator (HRSG) and a steam electrical generator designated as Unit 2.

The proposed KUA Cane Island Power Park Unit 3 is a nominal 250 MW combined cycle plant. It will include a nominal 167 MW stationary gas combustion turbine-electrical generator burning natural gas with fuel oil as backup; a supplementally gas-fired heat recovery steam generator to raise sufficient steam to achieve 250 MW in combined cycle operation; an 80-90 MW steam electric generator, a 44 MMBtu/hr heat input duct burner, a 130 foot stack; and a 100-foot bypass stack for simple cycle operation. New major support facilities for Unit 3 include a cooling tower, water and wastewater facilities, water storage tanks, storm water detention pond, 230 KV transmission line, and a 1.0 million gallon storage tank for back-up distillate fuel oil.

Emissions from Cane Island Power Park Unit 3 will be controlled by Dry Low NO_X (DLN) combustors or selective catalytic reduction (SCR) when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
003	Power Generation	One nominal 167 Megawatt Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1.0 Million Gallon Fuel Oil Storage Tank
005	Steam Generation	One 44 mmBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator (and 80-90 MW Steam Electrical Turbine)
006	Water Cooling	Cooling Tower

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-254

SECTION I - FACILITY INFORMATION

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X , 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOCs. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This Project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is greater than 75 MW. [F.S Chapter 403.503 (12) Definitions]

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act..

PERMIT SCHEDULE

- 01/xx/99 Notice of Intent published in __________
- 01/07/99 Distributed Intent to Issue Permit
- 12/10/98 Application deemed complete and sufficient for PSD review.
- 08/05/98 Received PSD Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on August 5, 1998
- Department/BAR letters to KUA dated August 17, and September 23, 1998
- Department/BAR memo to PPSO dated August 31, 1998
- Comments and letter from the National Park Service dated September 11, 1998.
- Department Statement of Sufficiency (Not Sufficient) dated October 8, 1998
- KUA Response to Statement of Sufficiency dated November 06, 1998
- KUA letter dated November 30, 1998 and Fax dated January 6, 1999
- Department's Intent to Issue and Public Notice Package dated January 8, 1999.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: 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. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the Decemebr 31, 2002 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]
8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

SECTION II - ADMINISTRATIVE REQUIREMENTS

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District Office. [Chapter 62-213, F.A.C.]

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., 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.]

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District Office by March 1st of each year.

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emissions Unit 003. Direct Power Generation, consisting of a nominal 167 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 004. Fuel Storage, consisting of a 1.0 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.

6. ARMS Emission Unit 005. Steam Power Generation, consisting of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 44 mmBTU/hr duct burner (HHV) and 80-90 MW steam electrical generator shall comply with all applicable provisions of 40CFR60, Subpart Dc, Standards of Performance for Small Industrial Commercial-Institutional Steam Generating Units Which Construction is Commenced After September June 9, 1989, adopted by reference in Rule 62-204.800(7), F.A.C.

7. ARMS Emission Unit 006. Cooling Tower, is an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because Chromium-based chemical treatment is not used.

8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

9. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 19°F temperature, 55% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,696 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,910 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 44 mmBtu/hour (HHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

12. 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.

13. 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 owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the 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 and the regulations. [Rule 62-4.130, F.A.C.]

14. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

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

16. Maximum allowable hours of operation for the 250 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is permitted for a maximum of 720 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation The plant may be operated in simple cycle mode. Different limits apply depending upon whether simple cycle operation is of an intermittent nature, such as due to maintenance of equipment following the combustion turbine or temporary electrical demand fluctuations, or of a longer term nature, such as a decision to not install the heat recovery steam generator or long term electrical demand situations.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine and Low NO_X burners shall be installed in the duct burner arrangement to comply with the NO_X emissions limits listed in Specific Conditions 24 and 25 [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

20. The permittee may design the heat recovery steam generator to accommodate installation of selective catalytic reduction or oxidation catalyst technologies and comply with the corresponding NO_X and CO limits listed in Specific Conditions 24, 25 and 26. [Rules 62-212.400 and 62-4.070, F.A.C.]

21. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 24 through 29. [Rule 62-4.070., Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

22. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

23. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

24. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15 % O_2. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions. Each Unit shall be tested alone to comply with the applicable NSPS and as a Combined Unit to comply with the BACT limits as indicated below: [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG and Dc), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	1.4 ppm (Gas, CT on, DB off) 4 ppm (Gas, CT and DB on)) 10 ppm for F.O.
CO	As Above	12 ppm (Gas, CT on, DB off) 20 ppm (Gas, CT and DB on) 30 ppm for F.O.
NO_X (CT on, DB off)	DLN, or DLN & SCR for gas WI or SCR for fuel oil 720 Hours on fuel oil with DB On or Off	9 ppm (DLN) or 6 ppm (SCR) for gas 42 ppm (WI) or 15 ppm (SCR) for fuel oil 12/42 ppm (gas/oil) Intermittent Simple Cycle
NO_X (CT and DB on)	DLN & Low NO_X, or DLN & SCR for gas WI & Low NO_X, or SCR for fuel oil Duct burner only fires natural gas	9.4 ppm (DLN) or 6 ppm (SCR) for gas 42 ppm (WI) or 15 ppm (SCR) for fuel oil DB limited to 0.4 lb/MW-hr

25. Nitrogen Oxides (NO_X) Emissions:

A. *Combined Cycle and Continuous Simple Cycle Operation*

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) and the duct burner off shall not exceed 9 (42) ppmvd at 15% O_2 (24-hr block average), and with the combustion turbine operating and the duct burner on shall not exceed 9.4 (42) ppmvd at 15% O_2 (24-hour block average). Compliance will be determined by the continuous emission monitor (CEMS). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 65 (303) pounds per hour (lb/hr) with the duct burner off and 68 (303) lb/hr with the duct burner on to be demonstrated by initial stack test. [40CFR60 Subpart GG and Rule 62-212.400, F.A.C.]
- If selective catalytic reduction (SCR) technology is installed, the concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) and the duct burner on or off, shall not exceed 6 (15) ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). Emissions of NO_X calculated as NO_2 in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 43 (108) pounds per hour (lb/hr) with the duct burner on or off to be demonstrated by initial stack test. [40CFR60 Subpart GG and Rule 62-212.400, F.A.C.]
- Unless SCR is employed, emissions of NO_X from the duct burner shall not exceed 0.4 lb/MW-hr (gross output). [Rule 62-212.400, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

B. Intermittent Simple Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 12 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 86 (303) pounds per hour (lb/hr). [Rule 62-212.400, F.A.C. and 40CFR60 Subpart GG]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

26. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall exceed neither 12 (20) ppm nor 43 (71) lb/hr with the duct burner off and neither 20 (30) ppm nor 71 (108) lb/hr with the duct burner on to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
27. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall exceed neither 1.4 (10) ppm nor 3 (21.4) lb/hr with the duct burner off and neither 4 (10) ppm nor 8.5 (21.4) lb/hr with the duct burner on to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]
28. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 720 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 49 and 50 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Emissions of SO_2 shall not exceed 38.1 tons per year. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. to avoid PSD Review]
29. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

30. 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 occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from combined cycle plant operation. During start-up to simple cycle operation, up to one hour of excess emissions are allowed.

During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

31. Excess emissions 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

32. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office 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. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 24 and 25. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1997 version)].

COMPLIANCE DETERMINATION

33. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

34. Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 33. Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as installation of SCR or change of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).

- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG, Dc. NO_X BACT limits compliance by CEMs (24-hr average or 3-hr average if SCR is installed).
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

35. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 32. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

36. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

37. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted.

38. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

39. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

40. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

41. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

42. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

43. Records: All measurements, records, and other data required to be maintained by KUA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

44. Compliance Test Reports: 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), F.A.C.

MONITORING REQUIREMENTS

45. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Condition No 24 and 25, shall be reported to the DEP Central District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1997 version)].

46. CEMS for reporting excess emissions: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

47. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on this Unit shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

48. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

49. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

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

50. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

51. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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]

52. Subpart Dc Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Dc].

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Cane Island Power Park Unit 3
Kissimmee Utility Authority
PSD-FL-254 and PA98-38
Intercession City, Osceola County, Florida

BACKGROUND

The applicant, Kissimmee Utility Authority (KUA), proposes to install a nominal 250 megawatt (MW) (net) combined cycle combustion turbine at the existing Cane Island Power Park, located at 6075 Old Tampa Highway, near Intercession City, Osceola County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 167 MW, General Electric PG7241FA (7FA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an 80-90 MW heat recovery steam generator (HRSG) with a steam turbine-electrical generator. Duct burners will be installed in the HRSG for supplemental firing to compensate for reduced combustion turbine capacity at high ambient temperature. The project also includes a new 1 million gallon storage tank for backup No. 2 fuel oil, cooling tower, 130 foot stack for combined cycle operation, and a 100 foot bypass stack for simple cycle operation. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated January 8, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on August 5, 1998 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. A revision was received on November 6 through a Response to Statement of Sufficiency.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E. and Teresa Heron, Permit Engineer

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (720 hr/yr) Combustion Controls	16 lb/hr (Gas, Baseload, 72°F)
Volatile Organic Compounds	As Above	4 ppm (Gas, Baseload) 10 ppm (Oil, Baseload)
Carbon Monoxide	As Above	25 ppm (Gas, baseload) 90 ppm (Oil Baseload)
Nitrogen Oxides	Dry Low NO_X Combustors Dry Low NO_X Burners Water Injection (Oil)	9 ppm @ 15% O_2 (CT) 0.08 lb/mmBtu (DB) 42 ppm @ 15% O_2 (Oil, baseload

The above limits apply only to baseload and primarily to gas operation. According to the application, the unit, would emit approximately 823-857 tons per year (TPY) of NO_X, 1,047-3,818 TPY of CO, 132-173 TPY of VOC, 37-38 TPY of SO_2, and 82-109 TPY of PM/PM_{10}. The basis for the higher values is 8,760 hours of operation with a maximum of 720 hours of oil firing.

BACT DETERMINATION PROCEDURE:

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

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

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

The duct burner required for supplementary gas-firing of the HRSG at high ambient temperatures is subject to 40 CFR 60, Subpart Dc, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. There are no NSPS-based emission limits for these small units when firing natural gas.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on recent BACT by EPA and the States for stationary gas turbine projects as large or larger than the one under review.

Project Location	Power Output and Duty	NO_X Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Lakeland, **FL**	350 MW CC CON	9/9/7.5 - NG 42/15/15 - No. 2 **FO**	DLN/HSCR/SCR WI/HSCR/SCR	230 MW WH 501G CT Initially 250 MW simple cycle and 25 ppm NO_X limit on gas
Mid-GA Cogen	308 MW CC CON	9 - NG 20 - No. 2 **FO**	DLN & SCR	2x119 MW WH 501D5A CTs
FPL Ft Myers, **FL**	1500 MW CC CON	9 - NG	DLN	6x170 MW **GE PG7241FA** CTs Non-BACT
Santa Rosa, **FL**	241 MW CC CON	9 - NG (CT) 9.8/6/6 (CT&**DB**)	DLN DLN/SCR/SNCR	**GE PG7241FA** CT. 6 ppm by SCR/SNCR if DLN fails
FPC Hines-Polk, **FL**	485 MW CC CON	12 - NG 42 - No. 2 **FO**	DLN WI	2x165 MW WH 501**FC** CTs Installed temporary SCR system
Tallahassee, **FL**	260 MW CC CON	12 - NG 42 - No. 2 **FO**	DLN WI	160 MW **GE** MS7231**FA** CT DLN guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC CON	7 - NG 9 - LPG, No. 2 **FO**	DLN & SCR	2x160 MW WH 501**F** CTs
Sithe/IPP, NY	1012 MW CC CON	4.5 - NG	DLN & SCR	4x160 MW **GE 7FA** CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW **GE 7FA** CTs
Barry, AL	800 MW CC CON	3.5 - NG (CT&**DB**)	DLN & SCR	3x170 MW **GE 7FA** CTs

CC = Combined Cycle
DB = Duct Burner
NG = Natural Gas
CT = Combustion Turbine
SNCR= Selective Non-catalytic Reduction
CON = Continuous
HSCR = Hot SCR
FO = Fuel Oil
ISO = 59°F
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
LPG = Liquefied Propane Gas
WI = Water or Steam Injection
Factors in Common with Kissimmee Utility Project are bolded.
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari
ppm = parts per million

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Mid-GA Cogen.	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
Fort Myers, FL	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Santa Rosa, FL	9 - NG (CT) 24 - NG (CT&DB)	1.4 - NG (CT) 8 - NG (CT&DB)	10% Opacity	Clean Fuels Good Combustion
FPC Hines-Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Barry, AL	0.034 lb/mmBtu - NG/CT 0.057 lb/mmBtu - CT/DB	0.015 lb/mmBtu After CT and DB	0.011 lb/mmBtu - CT/DB 10% Opacity	Clean Fuels Good Combustion

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

The following table is a sample of information on recent NO_X limitation by EPA and the States for combined cycle and cogeneration projects incorporating supplementary-firing in heat recovery steam generators.

Project Location	Duct Burner Rated Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu or ppm)	Technology	Comments
Plant Barry, AL	159	0.018 mmBtu/hr	DLN, SCR	3x170 MW GE 7FA CTs 3 Duct Burners
Santa Rosa, FL	600	9 - NG (CT) 9.8/6/6 (CT&DB)	DLN DLN/SCR/SNCR	Low NO_X Burners on DB Max 0.4 lb/MW-hr on DB
Saranac Energy, NY	553	0.08 lb/mmBtu	SCR	2 GE 7EA CTs with DBs Permit issued 1992
Bermuda HEL, VA	197	9 ppm	Steam Injection, SCR	1175 mmBtu/hr CT (1992)
Bear Island Paper, VA	129	9 ppm	SCR	474 mmBtu/hr CT (1992)
Pilgrim Energy, NY	214	4.5 ppm (CT) 0.012 lb/mmBtu (DB)	Steam Injection, SCR Low NO_X Burner, SCR	2 WH 501D5 CTs 2 Duct Burners
Selkirk Cogen, NY	206	9 ppm (CT) 0.018 lb/mmBtu (DB)	Low NO_X Burner, SCR	1173 mmBtu/hr CT
Grays Ferry, PA	366	9 ppm (CT) 0.09 lb/mmBtu (DB)	DLN Low NO_X Burner	WH 501D5A CT with DB DLN Failed, SCR Required

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the National Park Service dated September 11 1998
- Letter regarding Santa Rosa Energy Center from EPA Region IV dated August 11, 1998
- Letter from EPA Region IV dated , 1999 regarding KUA Cane Island Unit 3.
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the KUA project because natural gas will be the primary fuel and low sulfur fuel oil will be used only for 720 hours per year.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

The potential for NO_X emissions from gas-fired duct burners is lower than from gas turbines because of the lower temperature and pressure. In a supplementary-fired duct burner, the gas to the HRSG is raised from approximately 1100 °F (for F Class turbines) to less than 1800 °F. Thermal NO_X formation essentially ceases at temperatures below 2000 °F.[1] Since the fuel contains virtually no nitrogen, there is little potential for fuel NO_X formation.

NO_X Control Techniques

Wet Injection

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

Combustion Controls

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

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

The emission characteristics of General Electric's DLN 2 combustors while firing gas are given in Figure 2. NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity. The characteristics of the DLN-2.0 while firing fuel oil are shown in Figure 3. GE has since further upgraded its combustors and this description is not precise for its more advanced DLN-2.6.

Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the KUA project are shown in Figure 4. The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle to achieve 9 ppm of NO_X and 9 ppm of CO at somewhat less than 50 percent load. Presumably the emission characteristics of the DLN-2.6 are similar are similar to the DLN 2, except that the combustor emits NO_X at concentrations of 9 ppm (instead of the 25 ppm shown in Figure 2) at loads between 50 and 100 percent. Because of the "totally pre-mixed" design, emissions at less than 50 percent load are likely lower for the DLN 2.6 than the DLN-2.

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

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle), such as the F class. As in the case of wet injection, higher CO and hydrocarbon emissions can occur as a result of employing combustion controls to minimize NO_X. However the design of the DLN-2.6 combustor is such that low CO and VOC emissions are compatible with the low NO_X characteristics.

Figure 6 is a diagram of a typical in-line duct burner configuration and individual burner manufactured by Coen, one of the potential providers of this equipment. The unit will reside within the duct between the combustion turbine outlet and the HRSG. The oxygen-rich, hot turbine exhaust is used to burn natural gas introduced through the burner arrangement. In contrast to the pre-mixing that can be accomplished in the combustion turbine, not much (other than design optimization) can be done regarding the manner by which the very large volume of hot combustion air and the fuel are mixed prior to combustion. Basically the burners are described as Low NO_X burners.

There have been reports of lower emissions (on a lb/mmBtu or ppm basis rather than on a lb/hr basis) with the duct burners on. It has been theorized that the results are "suspect" and may have been cause by the "inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.".[2] It has also been theorized that transformations between NO and NO_2, interfere with the test method.[3] As previously mentioned, since the duct burner operates at a lower temperature and pressure than the gas turbine, it is possible that concentrations may actually be lower with the duct burner on.

<u>Selective Catalytic Combustion</u>

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. As of early 1992, over 100 gas turbine installations already used SCR in the United States. No combustion turbines in Florida employ SCR. Per the above table, only one combustion turbine project in Florida (FPC Hines) employs SCR. The equipment was installed on a temporary basis because Westinghouse could not meet its guaranteed limit by DLN technology by start-up. The Department was recently advised that SCR will also be installed at the previously permitted Seminole Electric Hardee Unit 3 project in anticipation of similar difficulties. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts 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.

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

In a manner analogous to balancing control of NO_X from the combustor with emissions of CO and hydrocarbon, similar balancing is required when controlling NO_X by SCR. Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit BACT limits as low as 3.5 ppm NO_X have been specified using SCR for an F Class project (with small in-line duct burners) in Alabama and proposed for another F Class project in Mississippi.

Selective Non-Catalytic Combustion

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

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. A supplementally-fired HRSG is defined as a HRSG fired to an average temperature not exceeding about 1800 °F. The 44 mmBtu/hr duct burner described by KUA will not likely achieve these temperatures close to this value. No SNCR applications are known for gas turbines with duct burners. Although it is one of the approved options for the Santa Rosa Energy Center, which incorporates a 600 mmBtu/hr duct burner, SNCR does not appear to be feasible for the KUA combustion turbine and supplementally-fired HRSG combined cycle project.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such 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 fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 720 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Annual emissions of PM_{10} are expected to be less than 82 tons for natural gas and less than 41 tons for fuel oil.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

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

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 Berkshire Massachusetts facility, 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the values of 25 and 90 ppm for gas and oil respectively at baseload proposed in the KUA's original application appear relatively high. At 70 percent of full load, these values are about 200 and 860 ppm for gas and oil respectively. These figures are based on the assumption that the duct burner does not operate. Although KUA did not submit a revision of its CO BACT request, the final choice of the GE PG7241FA with the DLN-2.6 combustors insures that emissions will be substantially less than the originally requested CO limits with or without catalytic oxidation.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC for both the turbine and the duct burner. The limits proposed for this project (prior to selection of the combustion turbine manufacturer) are 4 and 10 ppm for gas and oil firing respectively at baseload. At 70 percent of load, emissions were initially estimated at 4 and about 100 ppm for gas and oil firing respectively. According to GE, however, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[5] VOC concentrations will likely be less than 4 ppm for simultaneous operation of the combustion turbine and duct burner.

BACKGROUND ON SELECTED GAS TURBINE

KUA plans to the purchase a 167 MW (nominal) General Electric 7FA combined cycle gas turbine with a supplementary-fired heat recovery steam generator (HRSG) equipped with a small duct burner and a steam turbine-electrical generator to produce an additional 80-90 of electrical power. The 44 mmBtu/hr duct burner will incorporate a low NO_X design.

The first commercial GE 7F Class unit was installed at the Virginia Power Chesterfield Station in 1990.[6] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[7] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppm These actually achieved emissions of 13-25 ppm of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[8] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppm of NO_X, the City obtained a performance guarantee from GE of 9 ppm.[10] FPL also obtained a guarantee and permit limit of 9 ppm NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[11] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppm NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[12]

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[13] In its recent permits, separate and lower limits have been included in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppm.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[14] Although the permitted limit is 15 ppm, GE has already achieved emission levels of approximately 6-7 ppm on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[15] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as will be installed for KUA Cane Island Unit 3. Performance guarantees less than 9 ppm can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[16]

The 9 ppm NO_X limit on natural gas during baseload requested by KUA is typical compared with recent BACT determinations for F Class units, such as those previously listed. The 7 ppm value for the SCR option appears high compared to the recent Alabama Power and Mississippi Power projects.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[17]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the KUA project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 24 through 29.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	1.4 ppm (Gas, CT on, DB off) 4 ppm (Gas, CT and DB on)) 10 ppm for F.O.
CO	As Above	12 ppm (Gas, CT on, DB off) 20 ppm (Gas, CT and DB on) 30 ppm for F.O.
NO_X (CT on, DB off)	DLN or SCR, WI for F.O.	9 ppm (DLN) or 6 ppm (SCR) 12 ppm Simple Cycle (Intermittent) 42 ppm for F.O. (720 Hours Max.)
NO_X (CT and DB on)	DLN and Low NO_X, or SCR	9.4 ppm (DLN) or 6 ppm (SCR) 42 ppm for F.O. (720 Hours Max.) DB limited to 0.4 lb/MW-hr

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The DLN, SCR and wet injection-based NO_X limits are achieved by GE at its 7FA combustion turbines throughout the United States.
- KUA (like other companies) can obtain a guarantee from GE for DLN-2.6 combustors to meet a 9 ppm (by volume, dry @15% O_2) NO_X limit on a Class 7FA gas turbine.[18] The Department has reviewed CEMS data from Fort St. Vrain indicating that a similar unit with DLN-2.6 combustors consistently achieved less than 9 ppm NO_X in 1997 and typically exhibited emissions between 4 and 8 ppm.[19]
- The turbine emission limits while firing gas with the duct burner off comply with the NSPS and are approximately equal to recent Department limits applicable to new units at start-up.
- KUA can obtain a NO_X guarantee of 42 ppm while firing oil. It does not appear that GE will guarantee a lower limit by fuel injection. The unit is limited to only 720 hours per year under this mode and will only fire oil when gas supplies are disrupted or unavailable to KUA. Therefore, additional controls are not cost-effective unless SCR is installed to meet the 9 ppm limit while firing oil.
- If SCR is installed to meet the alternative 6 ppm limit for gas firing, it is estimated that the unit should be capable of achieving 15 ppm while firing oil without significant extra costs.
- The duct burner used for occasional supplemental firing at high compressor inlet temperatures will comply with the NSPS (Subpart Dc). It may cause slightly higher NO_X concentrations than permitted for the combustion turbine alone.
- If the NO_X limits cannot be met with DLN (and Low NO_X technology with the duct burner on), KUA must install SCR technology and meet correspondingly lower emission limits. KUA has the option of not using the duct burner if it is the cause of non-compliance.
- The unit will at times be operated in simple cycle mode, such as during HRSG outages and repair or during unforeseen electrical demand situations. Therefore substantial emission reduction must be accomplished at the combustion stage or at other locations upstream of the HRSG.
- During intermittent simple cycle operation, as described above, the Department will permit NO_X emissions of 12 ppm. This allows for the situation wherein SCR is installed in the HRSG for combined cycle operation while the DLN-2.6 combustors are tuned or drift to higher NO_X values. Prolonged operation of the unit in simple cycle mode will require that it meet the same 9 ppm limit by DLN through re-tuning or 6 ppm by SCR (probably hot SCR).
- KUA estimated the <u>overall</u> cost of SCR to achieve 15 and 9 ppm at $877 and 883 per ton removed starting with no control (200 ppm). KUA estimated the overall cost of achieving 9 ppm by DLN at $43 per ton. Overall costs to achieve 7.5 and 3.5 ppm increase to $153 and 205 per ton respectively. The levelized <u>marginal</u> costs by conventional SCR installed in the HRSG to reduce NO_X emissions to 7.5 and 3.5 ppm were estimated by KUA as $14,134 and 5,844 respectively per ton of NO_X removed after initial control by DLN to 9 ppm.

- The Department considers KUA's assumptions of $425,000 and $532,000 contingencies on the SCR unit to be on the high side. There should be a smaller contingency percent for the SCR unit than for the DLN combustors. If unforeseen expenses occur, these should be partly covered by the overall project contingency which is several million dollars. The assumption regarding replacement of 1/3 of the catalyst per year also appears high in view of the expected lifetime while firing natural gas (see Page BD-6) of "8 to 10 years" and "in excess of 4-6 years" for fuel oil firing. While it may be acceptable to base estimates on guaranteed life, the project might not be viable at all if it is assumed that individual components and systems have lifetimes equal only to guaranteed life.

- Correcting for the contingency and lifetime would yield marginal costs of approximately $4,500 to $5,000 per ton NO_X removed. This is in-line with the cost estimates reported by Southern Company for the Alabama and Mississippi projects.[20] These values are marginally cost-effective assuming a DLN combustor that achieves 9 ppm is available.

- If emissions are initially controlled by the DLN-2.6 combustors to 15 ppm (instead of 9 ppm), the incremental cost of SCR will be substantially lower than estimated by KUA. Based on GE's letter to Jacksonville Electric Authority, project costs are lower for the 15 ppm case. Therefore further emissions reduction from 15 to 3.5 ppm will easily be less than $4,000 per ton NO_X removed, particularly if a credit is applied for the lower cost of the 15 ppm DLN-2.6 guarantee. Additional savings would be incurred because less tunings would be required.

- SCR causes environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. At equal emission rates, DLN technology is a better control strategy than SCR. At higher emission rates, DLN can still be justified as BACT given the negative effects of SCR described above. Accordingly, the Department has set a range of emission limits and control methods based on the turbine and duct burner combustion technologies chosen by KUA.

- The Department's overall BACT determination is equivalent to approximately 0.16 lb/MW-hr by DLN/Low NO_X or 0.10 lb/MW-hr by SCR. For reference, the NSPS promulgated on September 3, 1998 requires that new Da units (such as boilers and large duct burners) meet a limit of 1.6 lb/MW-hr.

- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5) imposed by various agencies.[21]

- The Department rejects emission limits as low as 3.5 when employing SCR. Such a limit reflects emissions on the order of 0.015 lb/mmBtu heat input and cannot be reliably measured. For reference the lowest limit for a coal plant using SCR in Florida is 0.17 lb/mmBtu. Corrected for the higher efficiency of a combined cycle unit, a NO_X limit of 3.5 ppm is equivalent to 0.01 lb/mmBtu from a boiler.

- The Department considers a limit of 9.4 ppm (DLN and Low NO_X) or 6 ppm (SCR) as BACT for this combined cycle facility with a supplementally-fired HRSG. In addition the contribution of the duct burner to overall emissions cannot exceed 0.4 lb/MW-hr.

- VOC emissions of 1.4 ppm from the combustion turbine by Good Combustion proposed by the Department are at the lower end of values determined as BACT. However even lower values have already been achieved by the previous generation DLN 2 combustors on the GE's 7FA units after tuning. Similar VOC performance is expected with the DLN-2.6 combustors while firing natural gas. The limit of 4 ppm with the duct burner in operation is also quite low. The 10 ppm limit while firing fuel oil is readily achievable whether the duct burner is on or off.
- The CO concentrations of 12 ppm are low with the duct burner off. With the duct burner on, they will be less than 20 ppm which is within the range of recent Department BACT determinations for combustion turbines alone. The CO limit, during the limited hours of fuel oil firing, will be set at 30 ppm whether or not the duct burner is in operation.
- For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppm on gas while the limit for the FPL Fort Myers project is 12 ppm. Limits for the Santa Rosa Energy Center are 9 ppm with the duct burner off and 24 with the large duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 720 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy, and FPL Fort Myers projects in Florida as well as the Barry, Alabama project.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 32 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: One hour in simple cycle or following a shutdown less than or equal to 8 hours.
Warm Start: Two hours following a shutdown between 8 and 48 hours.
Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the HRSG has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[22]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section

Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

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

REFERENCES

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6 Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.

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14 Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program

15 Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.

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18 Letter. Sindel, M, GE to Connelly, J., JEA. NO_X Guarantee for GE Frame 7FA Units. December 8, 1998.

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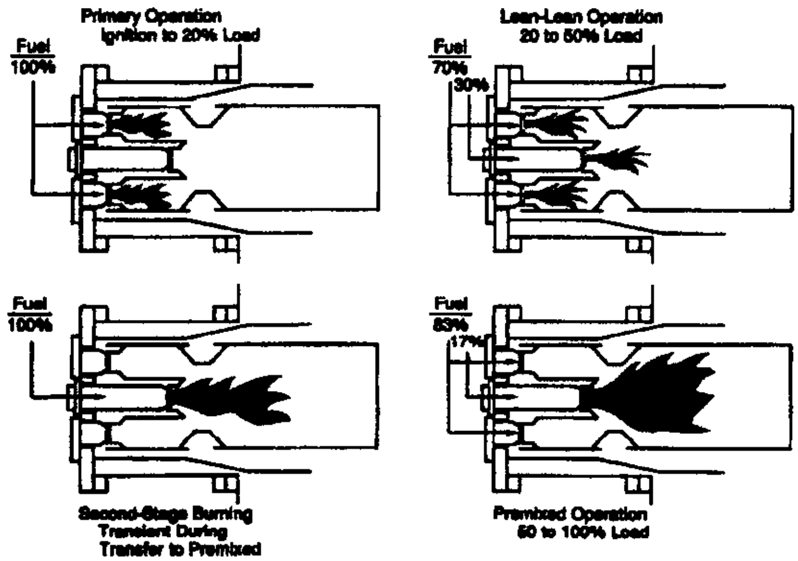
20 Telecon. Davidson, P., Southern Company, and Linero, A.A., FDEP. November 6, 1998. Rationale for 3.5 ppm Emission Limits at Alabama and Mississippi Projects.

21 Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

22 General Electric. Combined Cycle Startup Curves. June 19, 1998.



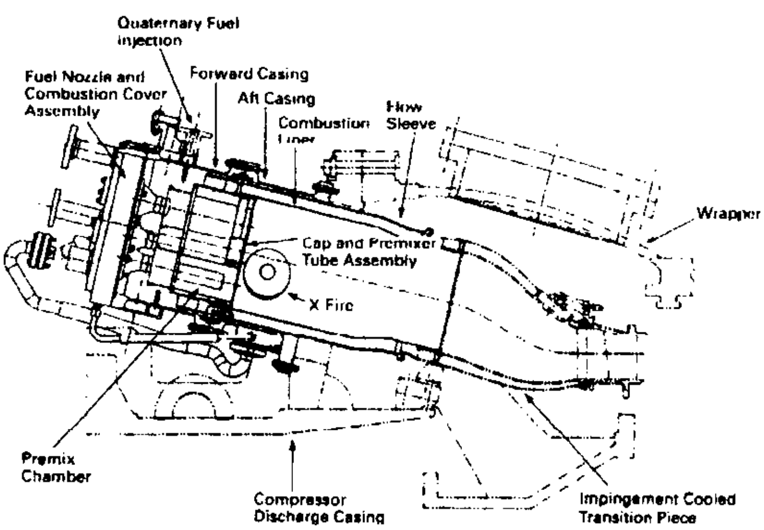


Figure 1 - Dry Low NOX Operating Modes - DLN-1

Cross Section of DLN-2.0

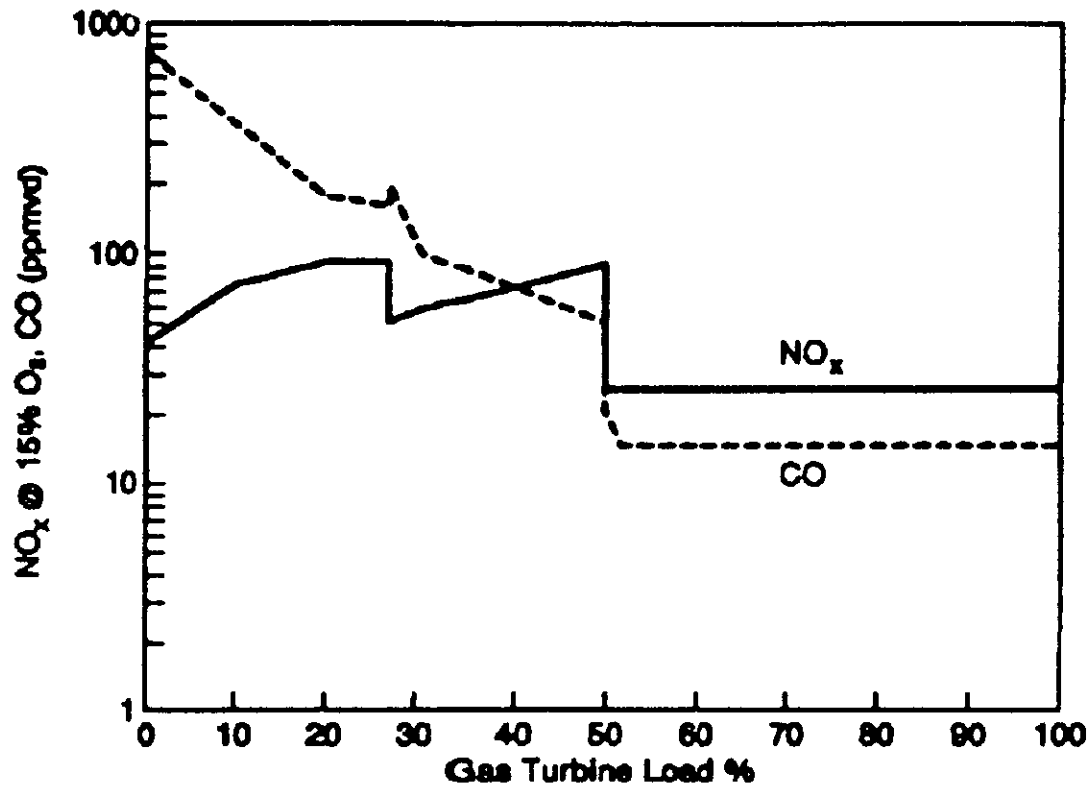


Figure 2 - Emissions Performance Curves for GE DLN-2 Combustors

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

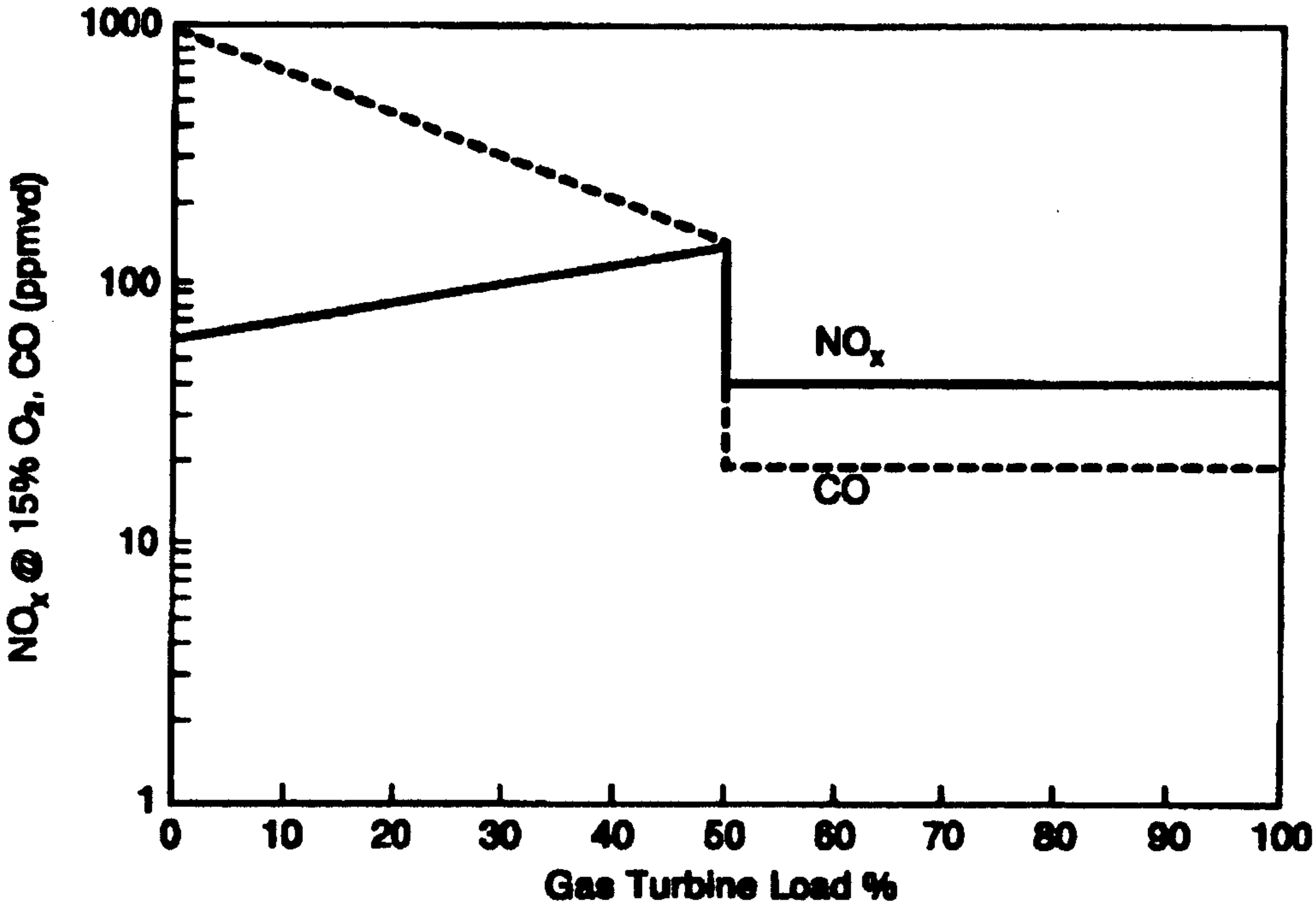


Figure 3 - Emissions Performance for DLN-2 Combustors

Firing Fuel Oil in Dual Fuel GE 7FA Turbine

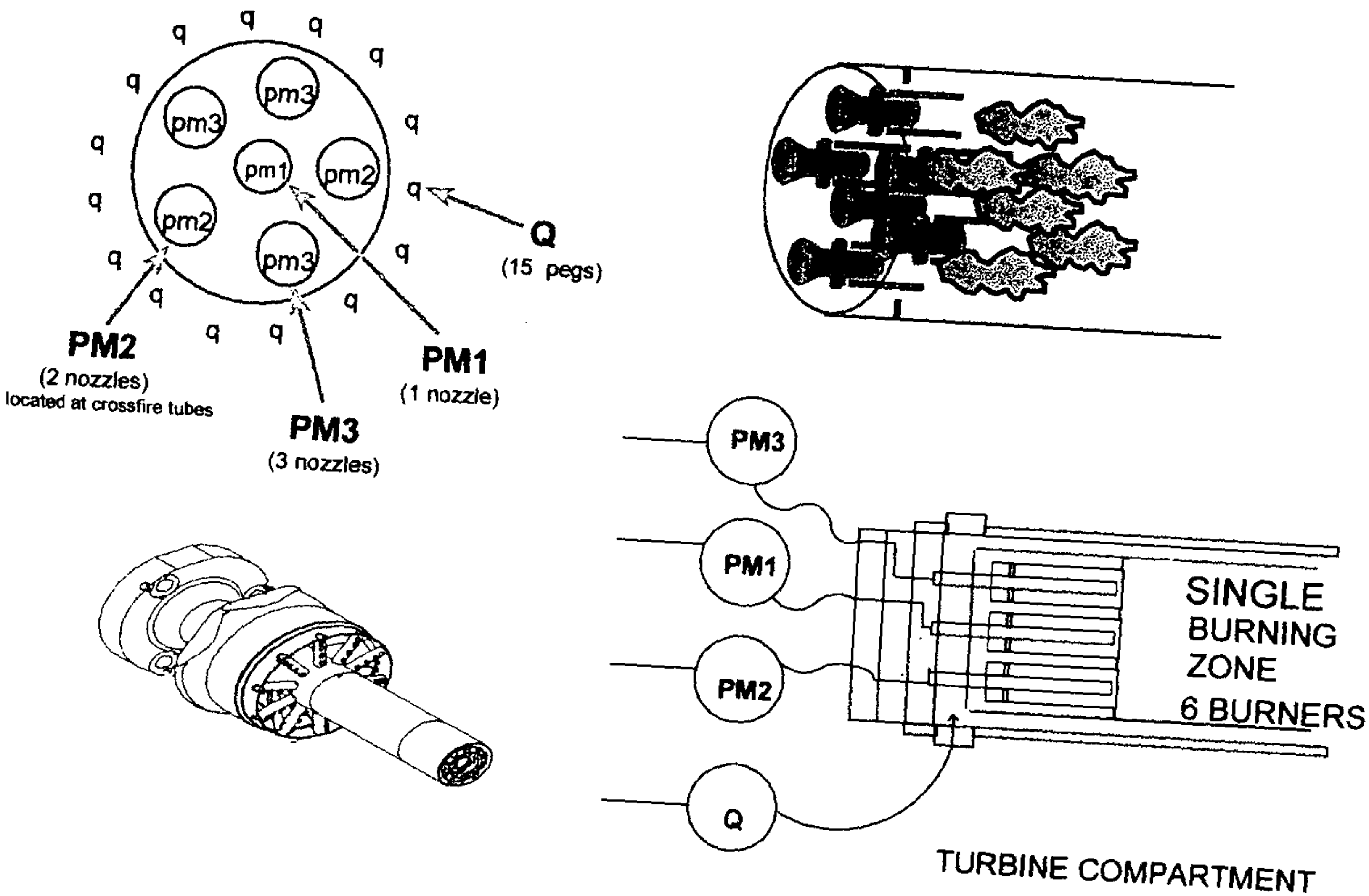


Figure 4 - DLN-2.6 Nozzle and Burner Arrangement

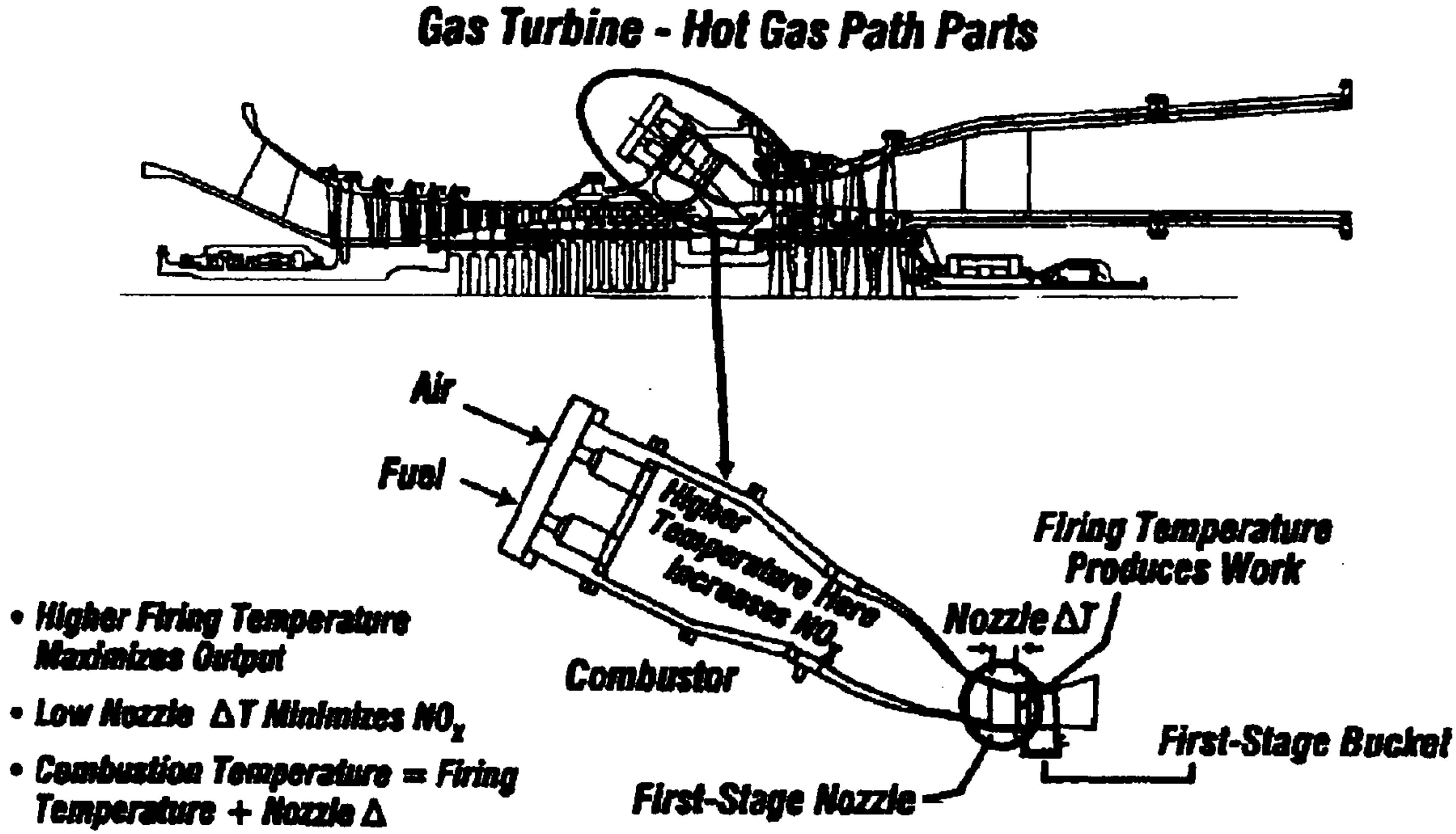
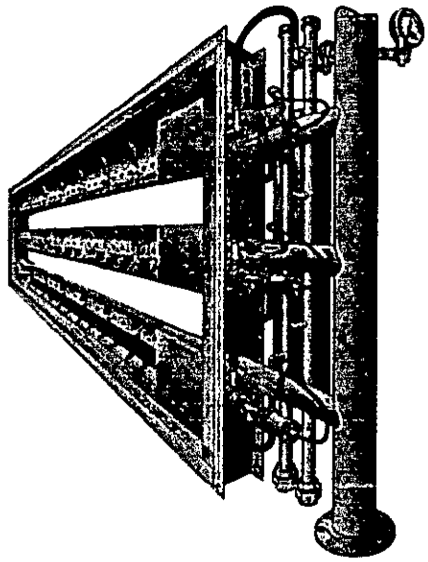
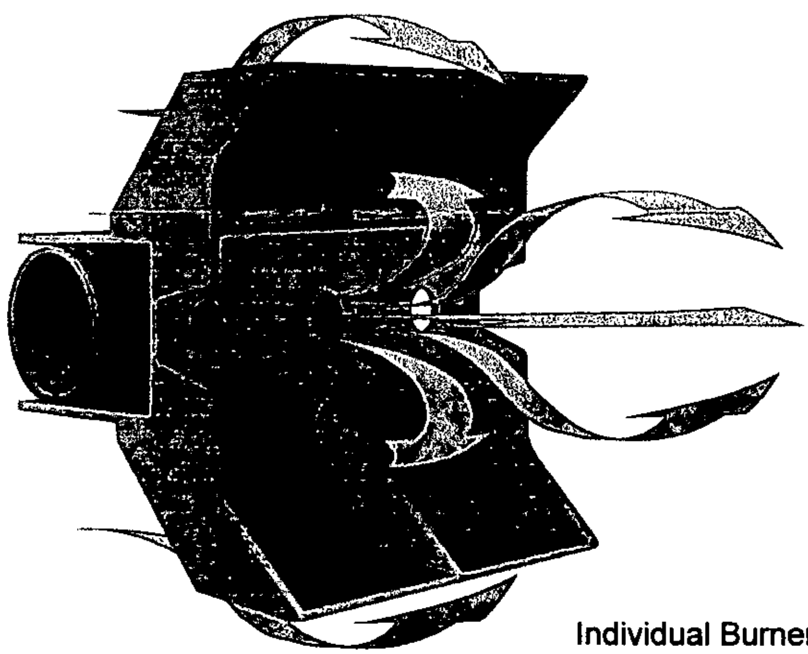


Figure 5 - Relation Between Flame Temperature and Firing Temperature

Burner Arrangment





Individual Burner

Figure 6 - Coen In-line Duct Burner and Arrangement

APPENDIX GC

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

P.E. Certification Statement

Permittee:

DEP File No. PSD-FL-254 (PA98-38)

Kissimmee Utility Authority (KUA)
Kissimmee, Osceola County

Project type:

Project will be at the KUA Cane Island Power Park near Intercession City, Osceola County. Project is construction of a 167 megawatt (MW) GE PG7241FA, gas and oil-fired, combined cycle combustion turbine with a supplementary-fired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80-90 MW via a steam-driven electrical generator. Project includes a 130-foot stack, a 100-foot stack for simple cycle operation, a 1.0 million gallon storage tank for back-up distillate fuel oil having a sulfur content of 0.05 percent. Fuel oil firing will be limited to 720 hours per year. Supplemental duct firing will be provided during high ambient temperature to maintain the nominal power.

Baseload nitrogen oxides (NO_X) limits are 9 ppm @15% O_2 for gas firing achievable by Dry Low NO_X and 42 ppm for oil firing by wet injection. Alternatively, KUA can choose selective catalytic reduction (SCR) technology to achieve lower values. Other pollutants, including PM/PM_{10}, CO, VOC, H_2SO_4, and SO_2 will be controlled by good combustion and use of clean fuels.

Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I (Chassahowitzka National Wilderness Areas) and Class II areas.

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

A. A. Linero — 1/7/99

A A. Linero, P.E. — Date

Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301 aal 1/7
Phone (850) 921-9523
Fax (850) 922-6979

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

FROM: A. A. Linero *AAL 1/5*

DATE: January 5, 1999

SUBJECT: KUA Cane Island Unit 3
250 MW Combined Cycle Plant (PSD-FL-254)

Attached is the public notice package for construction of a 167 MW GE PG7241FA gas-fired combustion turbine at the KUA Cane Island Power Park near Intercession City, Osceola County. The project includes a heat recovery steam generator to achieve the 250 MW at referenced conditions. A 1.0 million gallon storage tank will be constructed for the back-up distillate fuel that will be used for no more than 720 hours per year. Supplemental duct firing and inlet air cooling will be employed at high ambient temperature to partially compensate for loss of power output.

The basic unit is a nominal 167 megawatt General Electric PG7241FA gas and oil-fired combustion turbine-generator. The project includes a supplementary-fired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80-90 MW via a steam-driven electrical generator.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of 42 ppm NO_X will be achieved during the limited fuel oil use. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

The duct burner is rated at 44 mmBtu per hr and is small compared to any we were able to identify in our various technical and BACT searches. There are no NSPS limits for such small gas-fired duct burners. We believe Low NO_X technology for duct burners can maintain combined combustion turbine and duct burner emissions at 9 ppm, but allowed for the possibility of slightly higher emissions (9.4 ppm) when the duct burner is on. It will be used only at high ambient (turbine inlet) temperatures to maintain capacity.

Alternatively, emissions can be controlled by SCR. In this case, there would be some credits for the less expensive gas turbine combustors (meeting 15 ppm) needed to achieve a limit of 6 ppm in conjunction with SCR. These levels are equal to the determination recently made for the Santa Rosa Energy Center.

Although there have been recent BACT NO_X determinations as low as 3.5 ppm in Region IV we do not recommend such low values. Our recommended values equate to approximately 0.01 to 0.025 lb/mmBtu from a conventional coal-fired plant after correction for the higher thermal efficiency of the combined cycle. For example, the OUC Stanton II coal-fired plant achieves 0.17 lb/mmBtu with SCR.

The project is also subject to Site Certification. Early issuance of the intent will provide ample opportunity to have a public hearing (meeting) if one is requested.

I recommend your approval of the attached Intent to Issue.

AAL/aal

Attachments