Florida Department of
Environmental Protection

Memorandum

BAR

TO: Howard L. Rhodes

THRU: Clair H. Fancy CHF

FROM: A. A. Linero aal 2/17
Teresa Heron TH

DATE: February 17, 2000

SUBJECT: Gainesville Regional Utilities (GRU)
J.R. Kelly Generating Station (0010005-002-AC, PSD-FL-276)

Attached is the final permit package for construction of a nominal 133 MW GE 7EA combined cycle unit that will operate in conjunction with the existing Unit No. 8 steam turbine-electrical generator. The existing Unit 8 boiler will be shut down.

A PSD review and BACT determination was performed for CO and PM_{10}. Both of these pollutants will be controlled by good combustion of clean fuels. A cap on NO_X emissions of 133 tons on a calendar year basis was included to insure that PSD is not triggered for this pollutant. This reflects the 94 ton credit for the shutdown of the Unit 8 boiler.

The emission cap resolved EPA's initial insistence that SCR be installed. With the advice of EPA, we have limited the NO_X emissions while firing natural gas to 9 ppmvd at 15 percent O_2 on a 720 operating hour block average. This provides reasonable assurance that GRU will comply with the cap, but doesn't make them meet 9 ppmvd on an hour-by-hour basis. Fuel oil may be used up to 1000 hours per year during which emissions of 42 ppmvd are allowed.

During a "typical year" there will be no effect on GRU's operation of the unit. If the unit operates at a very high capacity factor and uses a lot of fuel oil, then the cap can become restrictive. The project will result in a total reduction of about 7,500 tons per year in allowable emissions of regulated pollutants and a nearly three-fold increase in maximum power capacity.

We recommend your approval of the attached Intent to Issue.

AAL/aal

Attachments

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 17, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Michael L. Kurtz, General Manager
City of Gainesville, GRU
Post Office Box 147117
Gainesville, Florida 32614-7117

Re: DEP File No. 0010005-002-AC (PSD-FL-276
J. R. Kelly Generating Station – Combined Cycle Project

Dear Mr. Kurtz:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the combined cycle project at the J. R. Kelly Generating Station near downtown Gainesville, Alachua County. The Department's Intent to Issue Air construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

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

Please submit any 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. Michael L. Kurtz, General Manager
City of Gainesville, GRU
Post Office Box 147117
Gainesville, Florida 32614-7117

DEP File No. 0010005-002-AC (PSD-FL-276)
Combined Cycle Repowering Project
Alachua County

INTENT TO ISSUE PSD PERMIT

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

The applicant, GRU, applied on September 7, 1999 to the Department for an air construction permit to install a nominal 133 megawatt combined cycle unit and auxiliary equipment and to retire the conventional boiler presently providing steam to the Unit 8 steam turbine-electrical generator at the J. R. Kelly Generating Station near downtown, Gainesville, Alachua County.

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

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

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

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

The Department will accept written comments 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 Air 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. The Department will hold a public meeting to explain the proposed permitting action and receive public comments from 7 to 9 p.m. on January 12, 2000 at the Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Alachua County.

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

C. H. Fancy

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-17-99 to the person(s) listed:

Michael L. Kurtz*
Yolanta Jonynas, GRU
Chair, Alachua County BCC*
Gregg Worley, EPA

John Bunyak, NPS
Chris Kirts, DEP NED
Pat Reynolds, DEP Gainesville
Tom Davis, ECT

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 12-17-99
(Clerk) (Date)

Z 031 391 905

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Michael Kurtz	
Street & Number GRU	
Post Office, State, & ZIP Code Gainesville 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 12-17-99 C010005-002-AC PSD-FI-276	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

- 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.

...e follow... ...an extra fee).

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

Consult postmaster for fee.

3. Article Addressed to:
Michael Kurtz
City of Gainesville, GRU
P O Box 147117 (A134)
Gainesville, Fl
32614-7117

4a. Article Number
Z 031 391 905

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

7. Date of Delivery
DEC 20 1999

5. Received By: *(Print Name)*
Larry Smith

6. Signature: *(Addressee or Agent)*
X Larry Smith

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

PS Form 3811

Thank you for using Return Receipt Service.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Alachua 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 Gainesville Regional Utilities. The permit is to construct a nominal 83 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine generator at the existing J.R. Kelly Generating Station in downtown Gainesville, Alachua County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM_{10}) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Gainesville Regional Utilities (GRU), Post Office Box 147117, Gainesville, Florida 32614-7717.

The proposed unit (Combined Cycle Unit CC-1) is a General Electric PG7121EA combustion turbine-electrical generator with an unfired heat recovery steam generator that will raise sufficient steam to produce approximately another (maximum) 50 MW via the existing Unit 8 steam-driven electrical generator. Upon installation of the new proposed unit, the Unit 8 steam boiler will permanently cease operation. Distillate oil will be used as back up fuel and limited to a 1000 hours per year. The turbine will able to operate in simple cycle (i.e. without HRSG or steam-electrical turbine). The project also includes: a 78 foot stack for simple cycle operation; a 100 foot stack for combined cycle operation; and a cooling tower (existing).

Emissions of PM_{10} and CO will be controlled by good combustion of clean pipeline supplied natural gas or maximum, 0.05 percent sulfur distillate fuel oil. The BACT determination for CO is 20 parts per million by volume (ppmvd). Typical expected CO emissions are 5-10 ppmvd. The BACT determination for PM_{10} is 5 pounds per hour (lb/hr) while burning natural gas and 10 lb/hr) while burning fuel oil with a visible emission limitation of 10 percent opacity. Nitrogen oxides (NO_X) emissions will be controlled by Dry Low NO_X technology capable of achieving 9 parts per million by volume (ppmvd) at 15 percent oxygen while firing natural gas and by wet injection achieving 42 ppmvd @15% O_2 when burning fuel oil. Sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC) will be controlled by good combustion of inherently clean fuels.

PSD and BACT do not apply for NO_X, SO_2, SAM, PM and VOC emissions. The maximum future potential (i.e. permitted allowable) annual emissions in tons per year are summarized below for comparison with recent past actual annual emissions from Unit 8 which is slated for retirement. The increases shown are based on future potential emissions minus past actual emissions.

Pollutant	Unit 8 (present potential)	Unit 8 (past actual)	CC-1 (future potential)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25
PM_{10}	296	1.8	24.4	22.6	15
SAM	160	1.3	5.4	4.1	7
SO_2	6,498	29	47.1	18	40
NO_x	1050	94	133 (cap)	39	40
VOC	12	2	9.2	7	40
CO	78	18	231 (yr 1)	213 (yr 1)	100
CO	78	18	189 (yr 2+)	171 (yr 2+)	100

The modest maximum increases in actual emissions and the very substantial reduction in total potential emissions will accompany a tripling of generation capacity compared with the existing Unit 8 and as much as a six-fold increase in actual power generation. The Department and GRU agreed to an emission cap for Unit CC-1 such that the total NO_X increase will be less than 40 TPY and thus exempt from PSD for that pollutant.

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 issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice. The Department will hold a public meeting to explain the proposed permitting action and receive public comments. The meeting will be held from 7 to 9 p.m. on January 12, 2000 at the GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue in Gainesville.

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

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

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

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.

Dept. of Environmental Protection	Dept. Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Northeast District Office	Northeast District Branch
111 S. Magnolia Drive, Suite 4	7825 Baymeadows Way, Suite 200B	101 NW 75 Street, Suite 3
Tallahassee, Florida 32301	Jacksonville, Florida 322256-7590	Gainesville, Florida 32607
Telephone: 850/488-0114	Telephone: 904/448-4300	Telephone: 352/333-2850
Fax: 850/922-6979	Fax: 904/448-4363	Fax: 352/333-2856

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

Gainesville Regional Utilities

J.R. Kelly Generating Station
Gainesville, Alachua County

133 Megawatt Combined Cycle Unit CC-1
Repowering of Unit 8

Facility I.D. No. 0010005
PSD-FL-276

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

December 17, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

City of Gainesville Utilities
Gainesville Regional Authority (GRU)
Post Office Box 147117 (A136)
Gainesville, Florida 32614-7117

Authorized Representative: Michael L .Kurtz – General Manager

1.2 Reviewing and Process Schedule

09-07-99:	Date of receipt of application
10-06-99:	BAR incompleteness letter
10-26-99:	Received initial GRU response to Department incompleteness letter
11-12-99:	Received additional GRU response to address U.S. FWS Comments
12-02-99:	Received further GRU response to address U.S. EPA comments
12-02-99:	Application deemed complete
12-16-99:	Received letter accepting nitrogen oxides emission cap.

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The J.R. Kelly Generating Station is located at 605 SE 3rd Street near the Downtown area of Gainesville, Alachua County. This site approximately 102 kilometers (km) south of Okefenokee National Wildlife Refuge (NWR), a PSD Class I Area. The site is 103 km northeast of the Chassahowitzka NWR Class I PSD Areas. The UTM coordinates of this facility are Zone 17; 372.0 km E; 3,280.2 km N.

Figure 1 – Regional Location **Figure 2 – Project Location, Gainesville**

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 existing facility (see Figure 3) presently generates electric power from two operational boilers and turbines (Units 7 and 8); three simple cycle combustion turbines (Units 1, 2,and 3); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancillary support equipment. Unit Nos. 7 and 8 have nominal nameplate electrical generation capacities of 25 and 50 MW respectively, and are fired primarily with natural gas with No.6 fuel oil serving as a back-up fuel source. Combustion turbine Units 1, 2, and 3 each have a nominal nameplate electrical generating capacity of 16 MW and are fired with natural gas and distillate fuel oil.

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 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 before start up. (Application received January 29,1999)

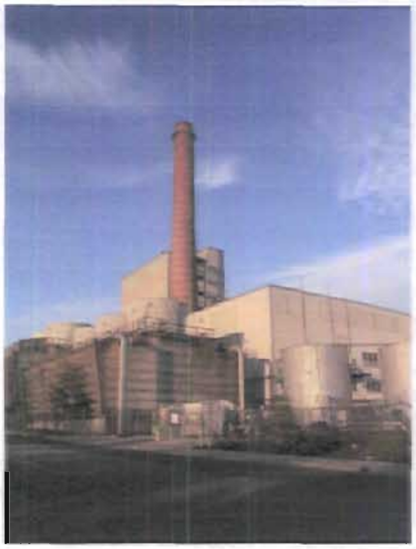

Figure 3 – J.R. Kelly Plant

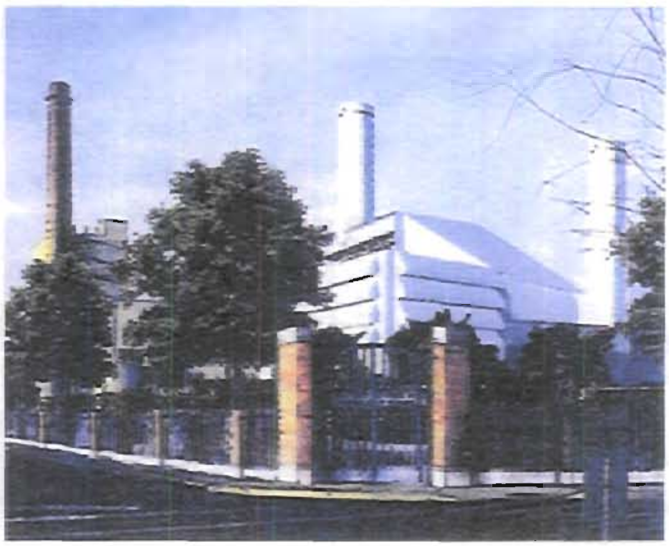

Figure 4 – Artist's Rendition of New Unit CC-1

3. PROJECT DESCRIPTION

This permit addresses the following emissions unit:

EMISSION UNIT	SYSTEM	Emission Unit Description
009	Power Generation	Unit CC-1. One nominal dual fuel 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

GRU proposes to construct/install a nominal dual fuel 133 megawatt (MW) combined cycle combustion turbine (Unit CC-1), at the existing J.R. Kelly Generating Station (see Figure 4 above). The project includes: a nominal dual fuel 83 MW, General Electric PG7121EA (7EA) combustion turbine-electrical generator fired primarily with pipeline natural gas; an unfired heat recovery steam generator (HRSG); two stacks; and ancillary equipment. The new unit will employ evaporative cooling and use the existing infrastructure including the existing Unit 8 steam turbine electrical generator, oil storage and support equipment. GRU will at times operate the unit in simple cycle mode. The existing Unit 8 boiler will be shut down and dismantled.

The turbine will be equipped with Dry Low NO_X (DLN) 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 1083 mmBtu/hr (gas) and 1121 mmBtu/hr (oil) based on the higher heat value (HHV) of the fuel and while operating at 20 °F and 100% load.

The main fuel will be natural gas and the unit will operate up to 8760 hours per year, of which no more than 1000 represent fuel oil operation. Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), volatile organic compounds (VOC), sulfuric acid mist (SAM) and nitrogen oxides (NO_X).

Emission increases of NO_X, SO_2, VOC, SAM and PM 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 and PM_{10} because emissions will increase by more than their respective significant emissions levels.

Unit CC-1 annual NO_X emissions will be limited by the credit from the Unit 8 boiler shutdown and an emission cap that will be rolled monthly and confirmed by a Continuous Monitoring System (CEMS).

4. PROCESS DESCRIPTION AND SELECTED COMBUSTION TURBINE

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the a compressor where it is compressed to a pressure ratio on the order of 10-30:1 depending on the unit. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2000 °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.

GRU plans to purchase a dual fuel nominal 83 MW General Electric 7EA combined cycle gas turbine with an unfired heat recovery steam generator (HRSG) and utilize the existing Unit No. 8 steam turbine-electrical generator to produce an additional 40-50 MW of electrical power.

An interior view of the GE 7E (a predecessor of the PG 7121EA) and an exterior view of the GE 7EA are shown in Figure 5. The GE 7EA has a 17 stage compressor that achieves a pressure ratio of approximately 12.8 to 1 and will be equipped with DLN combustors.

The GE 7EA is a "heavy duty gas turbine."[1] For reference, the larger GE 7FA and Westinghouse 501F turbines are rated at approximately 170 MW and are thus about twice the size of the 7EA. The latter units represent the largest units presently in commercial service in the United States.

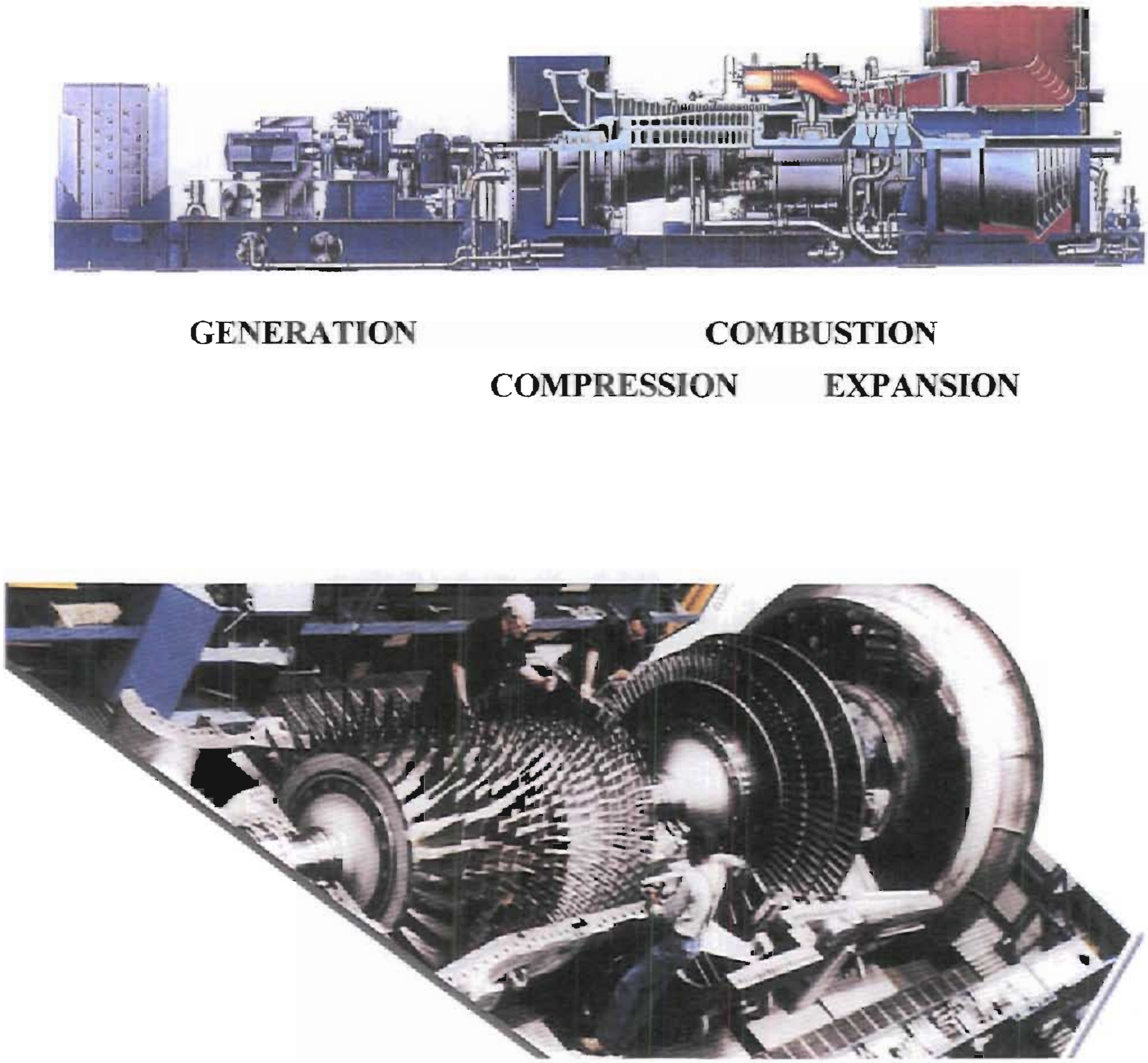

Figure 5 – Internal Diagram and View of GE 7E/EA

The 7EA has a firing temperature of over 2000 °F, a simple cycle efficiency of roughly 33 percent, and a combined cycle efficiency of about 50 percent. In contrast, the 7FA has a firing temperature of 2400 °F and a combined cycle efficiency of 56 percent. Because of the lower firing temperature, the 7EA achieved single digit NO_X emissions sooner and with less technological obstacles than the larger models.

In the GRU 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 6 is a process flow diagram for combined cycle operation. GRU 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. 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.

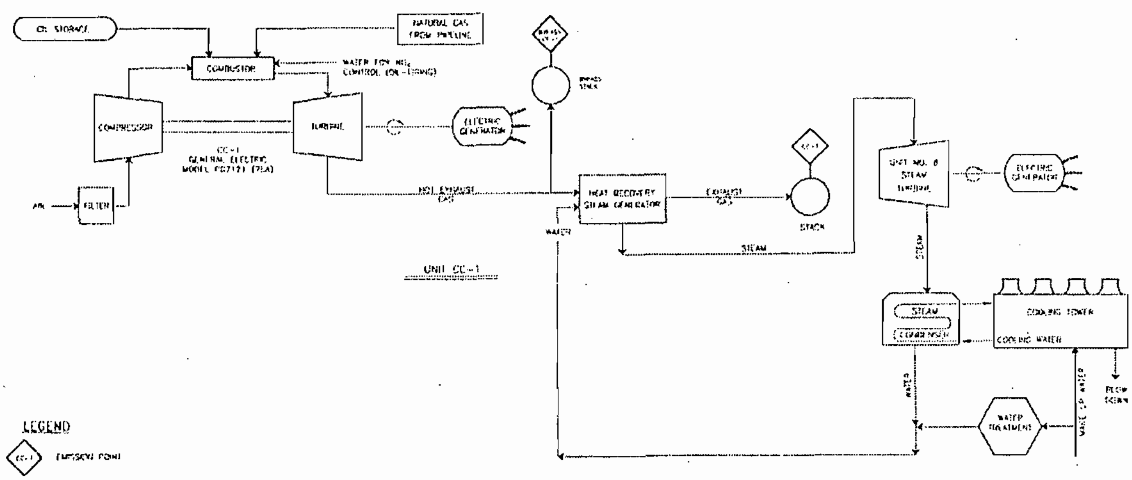

Figure 6 – Process Diagram for Combined Cycle Unit 1

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 10 MW compared to referenced temperatures), an evaporative chiller may be installed ahead of the combustion turbine inlet.

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.[2]

5. NON-BACT CONTROL TECHNOLOGY

A discussion of control technologies for CO and PM_{10} is given in the draft Best Available Control Technology determination accompanying this document. This section describes only the selected control technology for non-PSD (non-BACT) pollutants, including NO_X, VOC, SO_2 and SAM.

Nitrogen Oxides Formation

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas its use is proposed by GRU at 1000 hours per year.

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

NO_X Control Techniques for GRU Project

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

During natural gas operation, GRU will rely on combustion controls in the form of lean pre-mixed fuel combustion. 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 7 for the General Electric DLN-1 can-annular combustor similar to the model to be used in the GRU project. 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

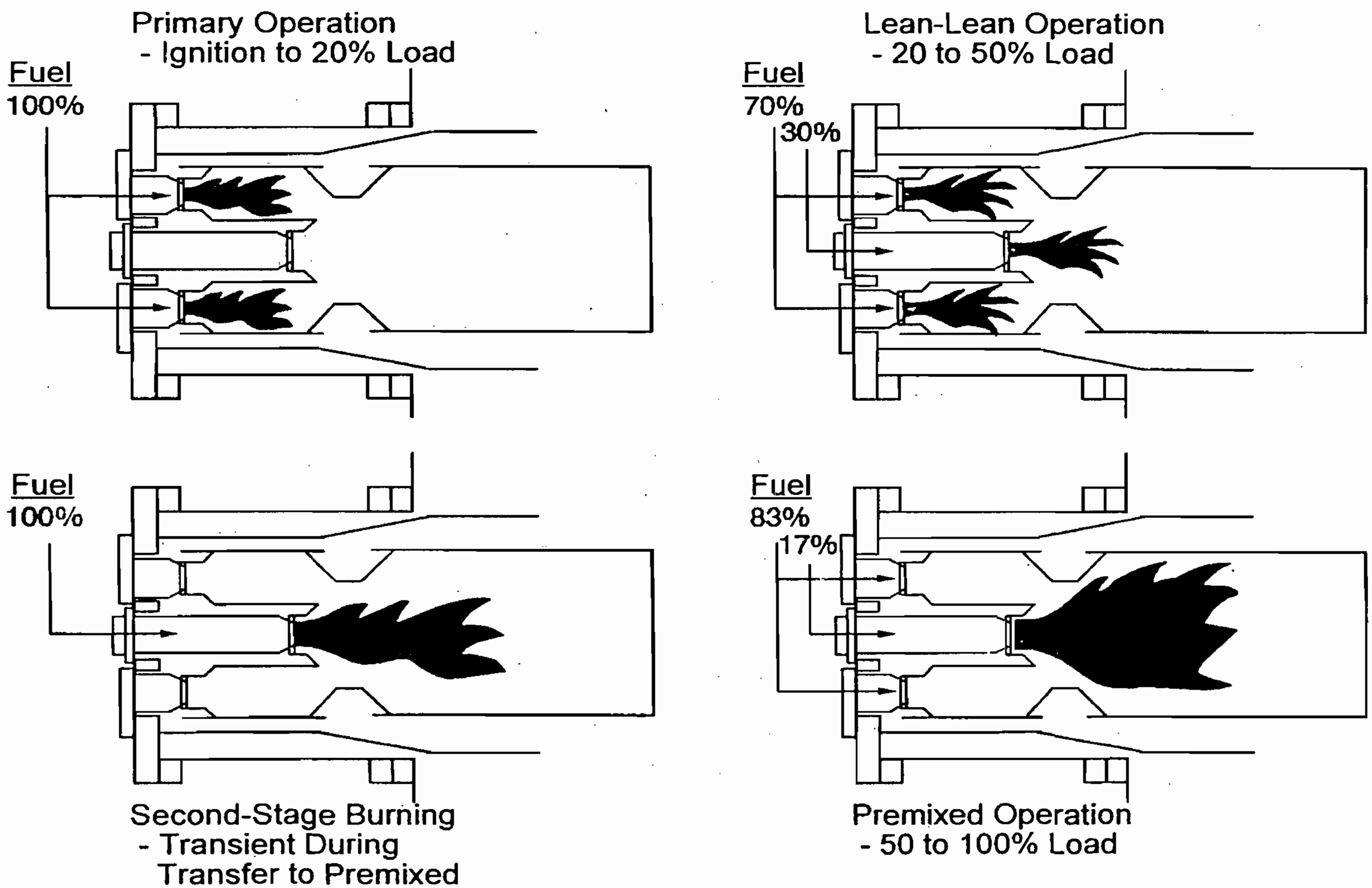

Figure 7 – Fuel-Staged Dry Low NO_x Operating Modes

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. At this stage the unit is considered to be in full pre-mix and emissions are controlled.

DLN-1 development began in the 1970s with the goal of producing a dry oil system to meet the USEPA's NSPS of 75 ppmvd at 15% O_2. GE's first DLN-1 system was tested both on oil and gas at Houston Lighting & Power in 1980 and met its emissions requirements.[3] A prototype DLN-1 system was later tested on a GE 7E combustion turbine at Anchorage Municipal Light and Power (AMLP) in early 1991 and entered commercial service shortly afterward.

During the early 1990s the DLN-1 was guaranteed to achieve less than 25 ppmvd NO_X on a GE 7EA combustion turbine. By the mid-1990's this model was guaranteed to achieve 9 ppmvd NO_X. As of 1996 several models such as the 6E, 7E, 6B, 7E, 7B-E, 7EA, 9E, 5P and 3J were DLN-1 equipped machines which achieved single-digit NO_X emissions in all cases. These units are smaller and have lower firing temperatures than the so-called F Class units such as the 170 MW GE 7FA or the Westinghouse 501F.

A cross section of a DLN-1 combustor is shown in Figure 8. This model has been progressively improved since its introduction. The emission characteristics of the an older version (25 ppmvd guarantee) of the DLN-1 combustor while firing natural gas are given in Figure 9. Characteristics while firing fuel oil are shown in Figure 10.

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

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 11 which is from a General Electric discussion on these principles.

The first GE 7EA project in Florida was at the Kissimmee Utilities Cane Island plant in 1993 followed by Polk Power Partners Mulberry Cogen in 1994 and GRU Deerhaven Station in 1995. These units were equipped with earlier versions of DLN-1 combustors to meet a permitted NO_X limit of 15 ppmvd O_2. All are currently operating and actually achieve emissions in the range of 7-11 ppmvd for NO_X. The Department recently issued a permit to TECO for a simple cycle GE 7EA combustion turbine with a permit limit of 9 ppmvd.[4] A draft permit was issued to FPC for three identical units, all of which have proposed permit limits of 9 ppmvd of NO_X.[5]

The requested 9/42 ppmvd NO_X limit on natural gas/fuel oil during baseload and operating in the simple or combined cycle mode is typical compared with some recent BACT determinations for E and F Class units.

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 Alachua 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

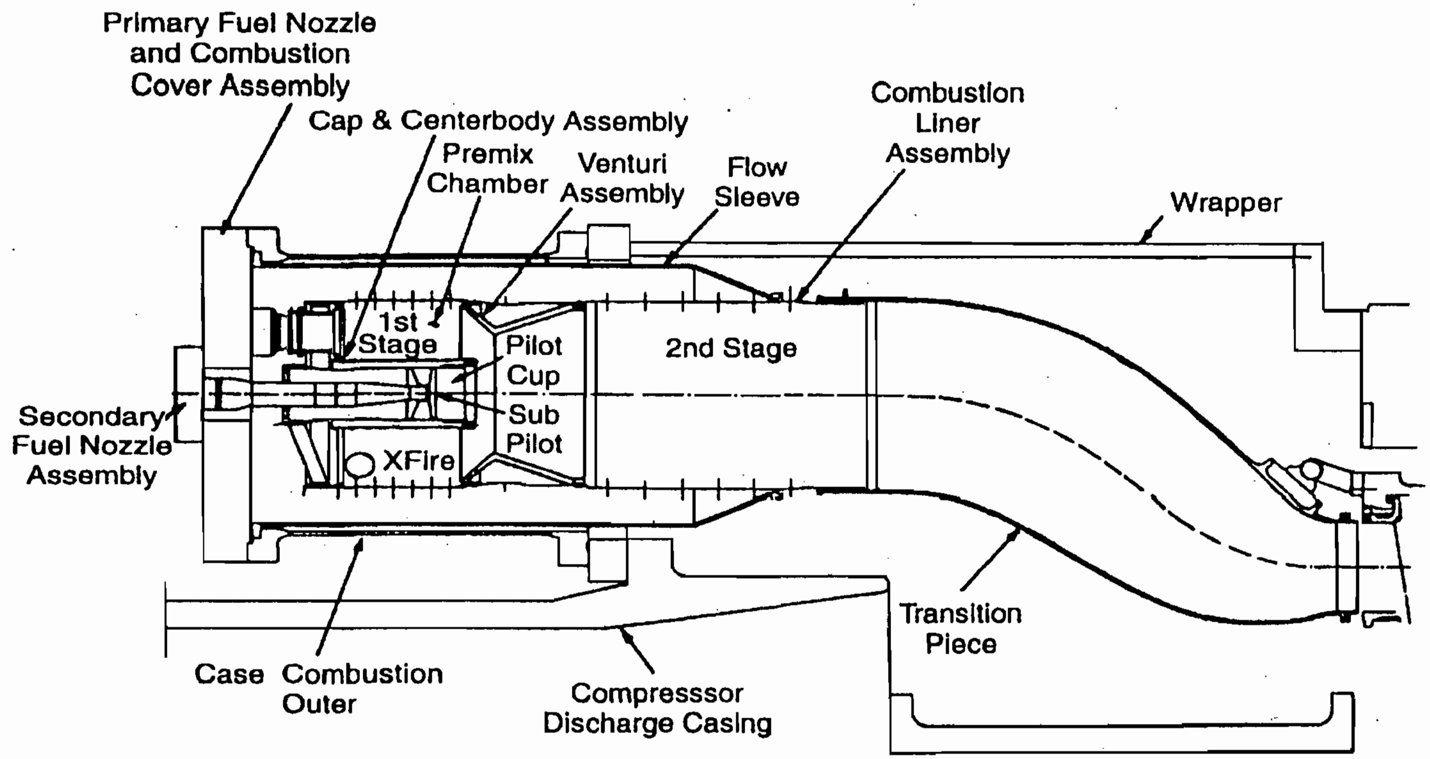

Figure 8 – Cross Section of GE 7EA Dry Low NO_x Combustion System

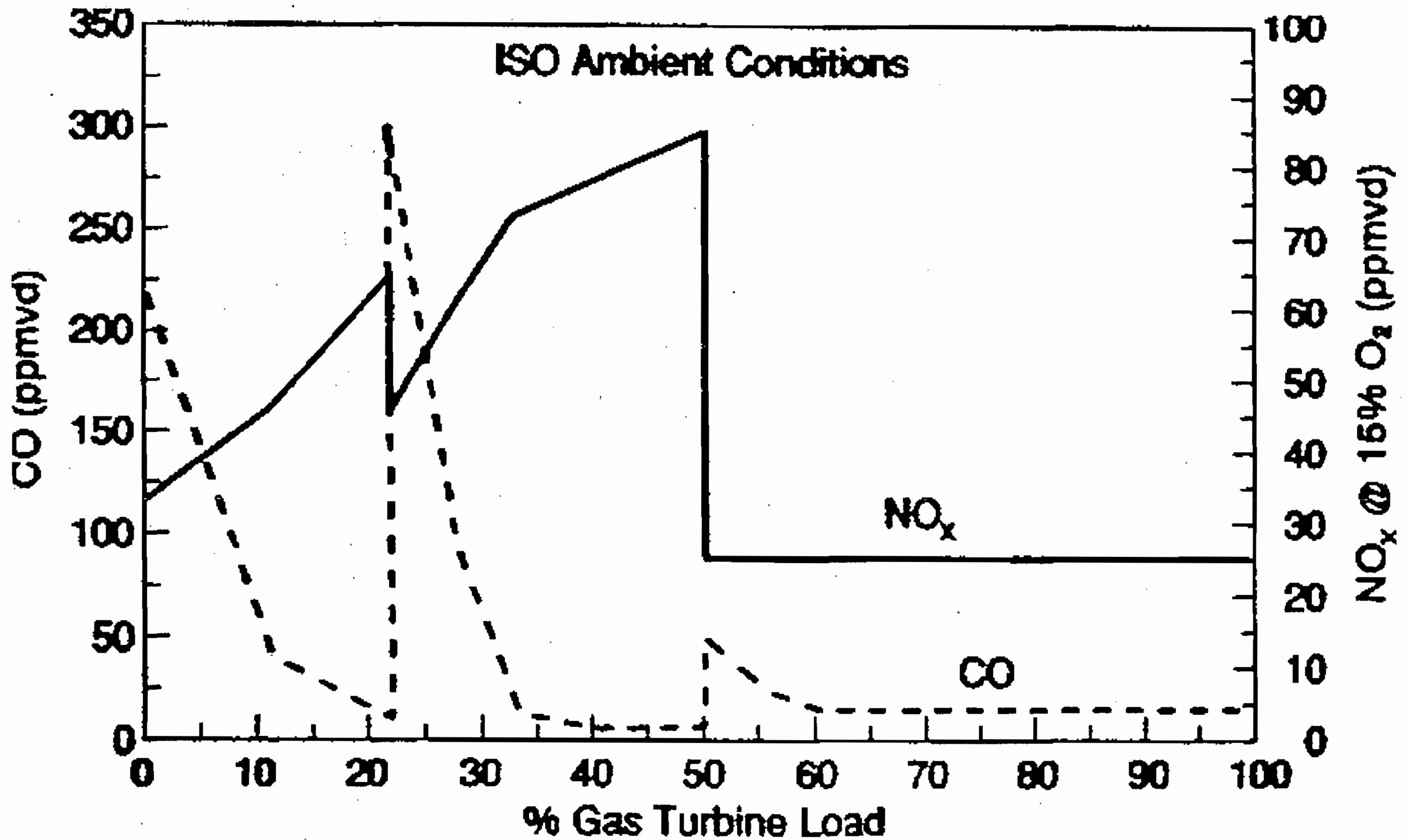

Figure 9 – GE 7EA DLN-1 Combustion System Performance on Natural Gas Fuel

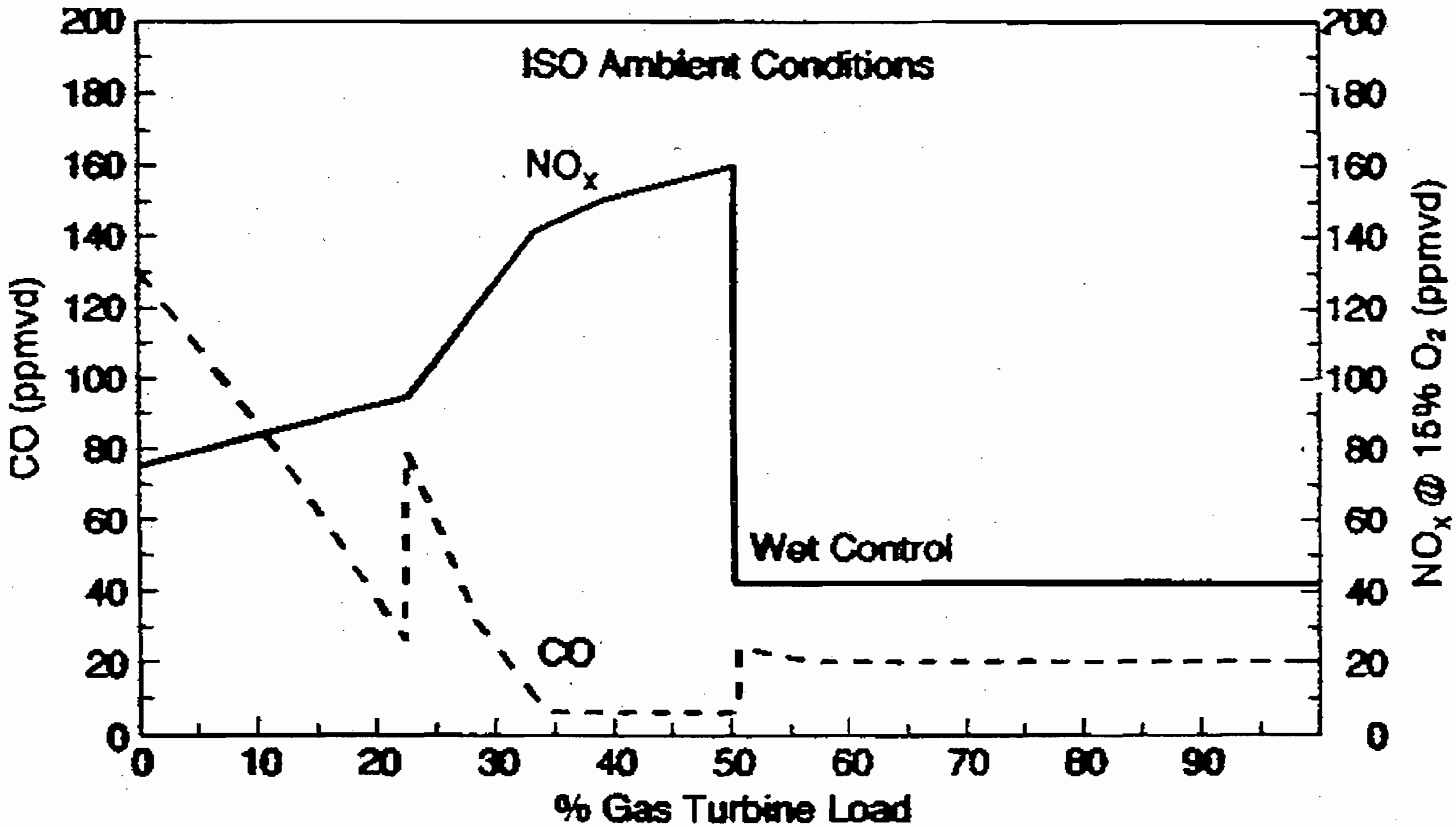

Figure 10 – GE 7EA DLN-1 Combustion System Performance on Distillate Oil Fuel

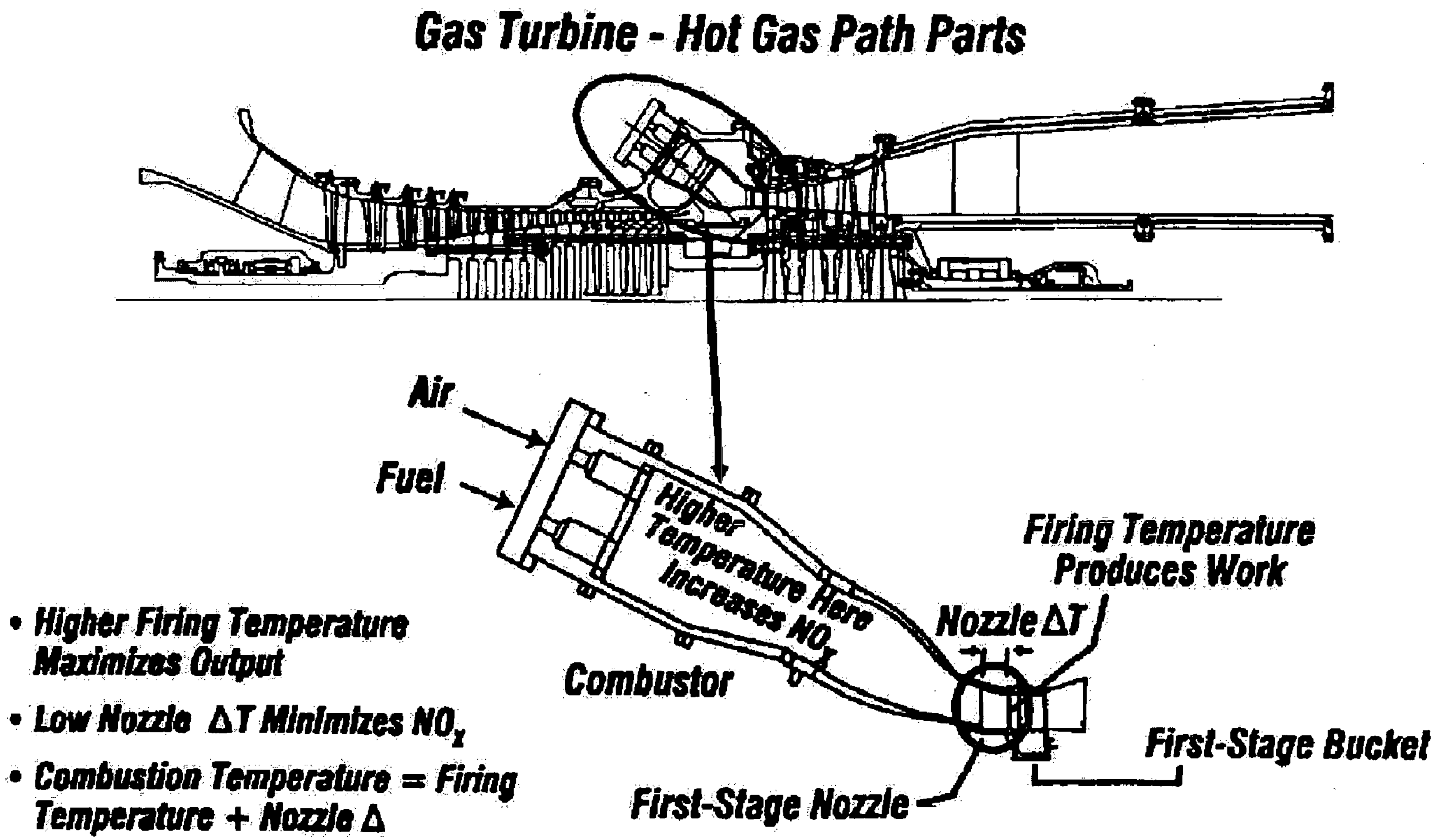

Figure 11 – Relation Between Flame Temperature and Firing Temperature

potential emission increases for PM_{10} and CO 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_{10} and CO. An analysis of the air quality impact from the proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

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

5.1 State Regulations

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

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

5.2 Federal Rules

40 CFR 60	NSPS Subpart GG
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 (SAM), mercury (Hg) and lead (Pb). 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. 16 through 21 of Draft Permit PSD-FL-276.

6.2 Emission Summary

PSD review is required for PM_{10} and CO. There will not be significant increases for NO_X, SO_2, SAM, PM and VOC emissions. The maximum potential emissions in tons per year for Unit CC-1 are summarized below for comparison with recent past annual emissions from Unit 8 slated for retirement. All units are in tons per year.

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Unit 8 (potential)	Unit 8 (past)	Unit CC-1 (future)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25 No
PM_{10}	296	1.8	24.4	22.6	**15 Yes**
SAM	160	1.3	5.4	4.1	7 No
SO_2	6,498	29	47.1	18	40 No
NO_x	1,050	94	133 (cap)	39	40 No
VOC	12	2	9.2	7	40 No
CO	78	18	231 (yr 1)	213 (yr 1)	**100 Yes**
CO	78	18	189 (yr 2+)	171 (yr 2+)	**100 Yes**

6.3 Air Quality Analysis

6.3.1 Introduction

The proposed project will increase emissions of two pollutants at levels in excess of PSD significant amounts: PM_{10}, and CO. PM_{10} is a criteria pollutant and has national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

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 analyses for these pollutants were not required. 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} and CO; and
- 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.

6.3.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all 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 Gainesville, Florida (surface data) and Waycross, Georgia (upper air data). The 5-year period of meteorological data was from 1984 through 1988. 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.

6.3.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the ISCST3 model was used in a screening mode to evaluate dispersion of emissions from the combined cycle facility for three loads (60%, 80% and 100%) and three seasonal operating conditions (summer, winter, and average). Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If this modeling at worst load conditions shows significant impacts, additional multi-facility modeling is required to determine the project's impacts on existing air quality and any applicable AAQS or PSD increments.

Receptors were placed around the facility, which is located in a PSD Class II area. They were also placed in the Okefenokee (ONWA) and Chassahowitzka (CNWA) National Wilderness Areas, which are the closest PSD Class I areas. The ONWA and CNWA are located approximately 102 km north and 103 km southwest of the project, respectively. A combination of fence line, near-field, mid-field, and far-field receptors were utilized for predicting maximum concentrations in the vicinity of the project. The fence line and near-field receptors consisted of discrete Cartesian receptors spaced at 50 meter intervals from the facility fence line out to the first mid-field polar receptor ring. The mid-field and far-field receptors consisted of polar receptor grids with 10 rings and 10° spacing radials. To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°. For predicting impacts at the ONWA and CNWA, discrete receptors were placed along the borders of the PSD Class I areas. 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 PSD Class I areas. The tables below show the results of the significant impact 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	0.04	1	NO
	24-hour	2.1	5	NO
CO	8-hour	8.3	500	NO
	1-hour	43.1	2000	NO

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

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	0.0004	0.2	NO
	24-hour	0.02	0.3	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	0.0006	0.2	NO
	24-hour	0.02	0.3	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.

6.3.4 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. Emission increases of acid rain and ozone precursors will be less than the significant emission rates. Therefore PSD review is required only for PM_{10} and CO.

The maximum ground-level concentrations predicted to occur for PM_{10}, and CO, (and SO_2 and NO_X) 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 low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize PM/PM_{10} generation and 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. Due to the distance of the source from the ONWA and CNWA PSD Class I Areas, plus the type and amount of emissions from the source, the U.S. Fish and Wildlife Service believes that there is a low potential for visibility impacts. Therefore, no regional haze analysis was required for this project.

Growth-Related Air Quality Impacts

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

The Public Service Commission has determined that power projects are needed to meet the low electrical reserve capacity throughout the State of Florida. The project is a response to local demand, state-wide and regional growth, and will accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," low water requirements, and the among the lowest air emissions per unit of electric power generating capacity for intermittent duty. Furthermore, the repowering project will results in the shutdown of an old boiler that would otherwise emit more pollution and produce less electricity if operated to meet future demand.

Hazardous Air Pollutants

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

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. Furthermore, it will replace a unit that has a potential to emit of about 8,000 tons per year of regulated pollutants with a unit that is limited to about 400 tons per year and which can produce nearly three times as much power.

A. A. Linero, P.E.
Teresa Heron, Engineer
Chris Carlson, Meteorologist

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APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Combined Cycle Repowering Project

BACKGROUND

The applicant, Gainesville Regional Utilities (GRU), proposes to install a nominal 133 megawatt gas and distillate fuel oil-fired combined cycle unit (Unit CC-1) at the existing J.R. Kelly Generating Station, located near downtown Gainesville, Alachua 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_{10}) and carbon monoxide (CO). 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 Rule 62-212.400, F.A.C.

The primary unit to be installed is a nominal 83 MW General Electric PG7121EA (7EA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) that will feed the existing Unit 8 steam turbine-electrical generator to produce another 40-50 MW. The project will result in the retirement of the conventional gas and residual fuel oil-fired steam generator that presently feeds the Unit 8 steam turbine-electrical generator. The project includes a 100 foot stack for combined cycle operation, and a 78 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 December 18, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on September 7, 1999 and included a BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. The application was revised on December 16, 1999 to reflect a cap on emissions of nitrogen oxides (NO_X).

REVISED BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs) 10 percent Opacity
Carbon Monoxide	Combustion Controls	25 ppmvd (gas – 1st year) 20 ppmvd (gas – after 1st yr) 20 ppmvd (fuel oil)

According to the revised application, Unit CC-1, will emit approximately 133 tons per year (TPY) of NO_X, 189 TPY of CO (after the first year), 9 TPY of VOC, 47 TPY of SO_2, and 24 TPY of PM/PM_{10}. Because of the shutdown of Unit 8 and an emission cap on NO_X, net emissions increases from the facility are projected to be 39 TPY NO_X, 171 TPY of CO (after the first year), 23 TPY of PM/PM_{10}, 18 TPY of SO_2 and 7 TPY of VOC. The basis for these values is 7,760 hours of operation on natural gas and 1,000 hours on distillate fuel oil.

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.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

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 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). There are no limits for CO or PM_{10} in Subpart GG. PSD was not triggered and a BACT determination is not required for NO_X or SO_2. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY STATES:

The following table is a sample of information on recent CO and PM_{10} BACT or emission limits set by Florida and Southeastern States for General Electric 7EA combustion turbines. The GRU project is included for comparison. The first two projects are for simple cycle installations.

Project Location	CO - ppmvd (or lb/mmBtu)	PM - lb/hr (and/or % opacity)	Technology	Comments
FPC Int. City, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	3x87 MW GE 7EA 12/99. 1000 hrs oil
TECO Hardee, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	One 75 MW GE 7EA. 10/99. 1000 hrs oil
Olin Cogen, AL	0.07 lb.mmBtu - NG (equals ~ 29 ppmvd))		Clean Fuels Good Combustion	One 80 MW GE 7EA 12/97. DB & PA
GE Plastics Cogen, AL	0.08 lb.mmBtu - NG (equals ~ 33 ppmvd)		Clean Fuels Good Combustion	One 80 MW GE 7EA 5/98. Duct Burner
GRU Gainesville, FL	20 – NG or FO 25 – NG 1st year	5/10 lb/hr - NG/FO 10 percent Opacity	Clean Fuels Good Combustion	One 83 MW GE 7EA Repower 1000 hrs oil

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 (per the application) will be used for a maximum of 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical. Annual emissions of PM_{10} are expected to be less than 24.4 tons.

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.

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.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. 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 will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[1]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations are typically permitted to achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. GRU proposes to meet a limit of 20 ppmvd while firing natural gas or fuel oil. GRU requests that it be allowed to initially meet a limit of 25 ppmvd when firing natural gas and to achieve 20 ppmvd after one year. The reason is that GE only offers a guarantee of 25 ppmvd for natural gas on a 7EA unit.

Although GE does not offer a single digit CO guarantee on the 7EA, according to its own reports, CO single-digit emissions have been achieved simultaneously with single-digit NO_X emissions on several MS7001EAs.[2] When the same units are operated at peak power, "expected" CO emissions are 6 ppmvd with an increase of NO_X to 18 ppmvd.

According to recent data reviewed by the Department, actual CO emissions from eight 7E units undergoing conversions to 7EA and DLN-1 technology achieved between 1.3 and 10.5 ppmvd of CO with an average of 5 ppmvd.[3] This was accomplished while the units achieved single-digit NO_X values. The Department expects similar actual performance from the GRU project.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the GRU project assuming full load.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM_{10}, VE	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs)) 10 Percent Opacity
CO	Combustion Controls	25 ppmvd and 54 lb/hr (gas – 1st year) 20 ppmvd and 43 lb/hr (gas – after 1st year) 20 ppmvd and 43 lb/hr (fuel oil)

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The top technology in a top/down analysis for PM_{10} control is good combustion control of inherently clean fuels. No further control methods are available.
- The values of 5 pounds per hour while burning natural gas and 10 lb/hr while burning fuel oil reflect BACT when coupled with a visible emissions limit of 10 percent opacity. The higher 10 lb/hr rate is limited by allowing only 1000 hours of back-up fuel oil use. Most years, fuel oil use will be substantially less than 1000 hours.
- The top technology in a top/down analysis for CO is installation of oxidation catalyst. Use of oxidation catalyst is not widespread except in CO non-attainment areas. It is used in attainment areas when a unit is used that has inherently high emissions of CO.
- GRU's consultant evaluated the use of an oxidation catalyst for the Unit 8 repowering project. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,324,708 with an annualized cost of $345,352 per unit. GRU consultant's estimated levelized costs for CO catalyst control at 2,029 per ton.

- The Department does not necessarily adopt this estimate, but would agree that these estimates would not be cost-effective for removal of CO (especially if emissions without control are actually much lower than 20 ppmvd as discussed above).
- The Department will set CO limits achievable by good combustion at full load as 25 ppmvd (first year of operation) and 20 ppmvd (gas) and 20 ppmvd (oil). These values are equal to those at the recently permitted 7EA units in Florida. They are similar or slightly higher than values from permitted "F" combustion turbines operating in either combined cycle or simple cycle mode. The reason is that the lower firing temperatures of the 7EA units versus the 7FA units results in less burn-out. As discussed above, the Department expects CO emissions to be in the 5 ppmvd range (even when NO_X emissions are 9 ppmvd), but does not want to force a lower guarantee from GE at an excessive cost to GRU.
- 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}.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Particulate (PM_{10})	By VE tests. EPA Method 5 if a special test is needed
Carbon Monoxide	Method 10 (can use RATA if at capacity)

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:

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

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

REFERENCES

[1] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[2] Paper. Davis, L.B., GE. Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines. 1998.

[3] Paper. Ihfe, L.M., et. al., Texaco P&G. Kern River and Sycamore Cogen Plant Uprates and Emission Compliance. Power-Gen Conference. New Orleans, Louisiana. November 30, 1999.

PERMITTEE:

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a 100 foot stack for combined cycle operation; a 78 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). 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

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel-oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 7 and 8 have nameplate ratings of 25 and 50 MW respectively.

Unit No.8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One nominal dual fuel 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

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 September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ______ 1999
- Department's Final Determination and BACT determination issued with this Final Permit.

SECTION II - 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 Blair Stone 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 Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

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 as defined in Rule 62-210.200 F.A.C.. 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. Construction 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. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 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 December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.070(3) F.A.C., 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 30 days prior to the expiration of the permit (Rule 62-4.080, F.A.C.).

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 Northeast 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 Northeast District and Northeast District Branch Offices 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. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334, excess as otherwise specified herein (See Condition 39). Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit 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 when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: 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

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide and particulate matter smaller than 10 microns..

4. Applicable Regulations: 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 (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. 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.]

GENERAL OPERATION REQUIREMENTS

5. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur 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)]

6. Combustion Turbine Capacity: The maximum heat input rates, based on the Higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 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)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

8. 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 Northeast District Office and Northeast District Branch 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.]

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 and 62-210.650, F.A.C.]

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for each unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070, and 62-210.650, F.A.C.]

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, NO_X, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO, NO_X, and VOC emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, to comply with the permitted emission limits. [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.]

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

EMISSION LIMITS AND STANDARDS

15. Nitrogen Oxides (NO_X) Emissions:

- Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 30-day rolling average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]
- Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 3-hour rolling average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule 62-212.400, F.A.C.]
- Emission Cap. Total emissions of NO_X shall not exceed 133 tons on a consecutive 365 day basis, rolled daily. Compliance will be demonstrated by the CEMS. [Applicant Request, Rule 62-4.070, F.A.C., escape PSD requirements of Rule 62-212.400, F.A.C.]

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd. Emissions of CO shall not exceed 54 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
- Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed 43 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

18. 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 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable NSPS SO_2. [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]

19. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

20. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching 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 as follows:

- During "cold start-up" to combined cycle plant 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.
- Unless authorized by the Department.

Excess emissions are defined as one-hour periods when NOx emissions are above 9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively.

Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours. NO_X CEM data shall be recorded and included in calculating the NO_X emissions cap. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These excess emissions shall be included in the 30-day rolling average (gas) and the 3-hr average (oil) for NO_X.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

23. Compliance Time: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. 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 change of combustors. Year two (YR2) compliance testing for CO shall be performed in the second year of operation. 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 this 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). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (YR2 gas only, I and 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. Test data shall be corrected to ISO conditions.

- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

25. 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 30-day rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 30 days. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]
- Compliance with the NO_x emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. [Rules 62-4.070(3) F.A.C., 62-210.700, F.A.C., and 40 CFR 75]
- 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. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless not authorized by 62-210.700 F.A.C.
- Periods when the 30-day rolling average (gas), 3-hr average (oil) or the 365 day rolling average NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.

26. Continuous Compliance with the NO_X Emission Cap: NO_X data collected by the CEMS shall be used to demonstrate compliance with the 365-day rolling NO_X emissions cap for each calendar day of operation by the following method:

- For each hour of operation (including startup and shutdown), the NO_X CEMS shall calculate and record the hourly NO_X emissions in units of pounds per hour, rounded to the nearest tenth of a pound. Each hourly emissions rate shall be calculated using at least two valid data points at least 15 minutes apart.
- For each calendar day of operation, the NO_X CEMS shall calculate and record the daily NOx emissions in units of pounds per day, rounded to the nearest tenth of a pound. Daily emissions rates shall be the sum of all recorded hourly emissions rates.
- For each calendar day of operation, the NO_X CEMS shall calculate and record the 365-day rolling total in units of tons, rounded to the nearest hundredth of a ton. The 365-day rolling total shall be the sum of all recorded daily NO_X emissions rates for the applicable 365 consecutive day period. NO_X emissions shall be recorded as "zero" for any days occurring prior to initial startup of the combustion turbine. [Rule 62-4.070(3), F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.]

27. 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) (1998 version).

28. 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.

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

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 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 110 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.

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices 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).

32. 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.

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU 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.

35. 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.

36. Excess Emissions Report: If excess emissions occur (as specified in Condition 39) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast District Branch Offices 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. 15 through 17. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (version)].

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): 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. Upon request from EPA or 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. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The CEMS NOx shall be used to determine periods of excess emissions. One-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas and fuel oil, respectively shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when short-term NO_X emissions [i.e., 30-day rolling average (gas) and 3-hour average (oil) or the annual total (i.e., 365-day rolling average) are above the emission limitations listed in Specific Condition No 15, shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked 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 (version)].

40. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

41. CEMS Certification and Quality Assurance Requirements: 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.

42. Custom Fuel Monitoring Schedule (Natural Gas): Subject to EPA approval, monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meet the definitions (40CFR 72). 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 natural gas or pipeline supplied natural gas.
    - SO_2 emissions shall be monitored 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 natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

43. Custom Fuel Oil Monitoring Schedule: Subject to EPA approval, 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).

44. 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, weight hoppers, flow meters, and tank scales, pressure gauges, etc., 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].

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 for CO and PM_{10} (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.

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

FROM: A. A. Linero AAL 12/16

DATE: December 16, 1999

SUBJECT: Gainesville Regional Utilities (GRU)
J.R. Kelly Generating Station (0010005-002-AC, PSD-FL-276)

Attached is the public notice package for construction of a nominal 133 MW GE 7EA combined cycle unit that will operate in conjunction with the existing Unit No. 8 steam turbine-electrical generator. The existing Unit 8 boiler will be shut down.

A PSD review and BACT determination was performed for CO and PM_{10}. Both of these pollutants will be controlled by good combustion of clean fuels. A cap on NO_X emissions of 133 tons on a 365 day basis rolled daily is included to insure that PSD is not triggered for this pollutant. This reflects the 94 tons credit for the shutdown of the Unit 8 boiler. Additionally NO_X emissions while firing natural gas will be limited to 9 ppmvd at 15 percent O_2 on a 30-day rolling average. Fuel oil may be used up to 1000 hours per year during which emissions of 42 ppmvd are allowed.

During a "typical year" there will be no effect on GRU's operation of the unit. If the unit operates at a very high capacity factor and uses a lot of fuel oil, then the cap can become restrictive. GRU supplied a letter to revise the application and request the cap. The project will result in a total reduction of about 7,500 in allowable emissions of regulated pollutants and a nearly three-fold increase in maximum power capacity.

I recommend your approval of the attached Intent to Issue.

AAL/aal

Attachments

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. Certification Statement

Permittee: **DEP File No.** 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities (GRU)
Gainesville, Alachua County

Project type:

Project will be at the GRU J.R. Kelly Generating Station near Downtown Gainesville, Alachua County. Project is construction of a nominal 83 megawatt (MW) GE PG7121EA, 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 40-50 MW via an existing steam-driven electrical generator. Project also includes: a 100-foot stack, a 78-foot stack for simple cycle operation; a cooling tower for pond water (existing) and a small heater to heat the natural gas prior to use in simple cycle operation.

Nitrogen oxides (NO_X) limits are 9 ppmvd @15% O_2 (30-day average) for gas firing achievable by Dry Low NO_X and 42 ppmvd (3-hour average) for oil firing by wet injection. 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 and Okeefenokee) 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, P.E. 12/16/99
Registration Number: 26032 Date

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

A. A. LINERO
CERTIFICATE
NO. 26032
12/16
STATE OF
FLORIDA
REGISTERED ENGINEER

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

Via Telefax

RECEIVED

OCT 27 2000

BUREAU OF AIR REGULATION

October 26, 2000

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Florida Dept. of Environmental Regulation
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station (Facility ID No. 0010005)
Combined Cycle No. 1 (PSD-FL-276)
Notice of Anticipated Initial Startup Date

Dear Mr. Fancy:

In accordance with 40 CFR 60.7(a)(2) notice is hereby provided that the anticipated date of initial startup of the above-referenced unit is November 27, 2000. Initially, the unit will operate in simple cycle mode; combined cycle operation is not projected until sometime in February 2001. Notice of the actual startup date will be provided within 15 days of such date.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
C. Kirts, FDEP - NE District Office
R. Klemans
L. Lalwani, FDEP - NE District Branch Office
A. Linero, FDEP - Tallahassee
S. Manasco
G. Swanson
D. Thompson
JRK CC1

JRKCC1initstartup.y36

GRU

GAINESVILLE REGIONAL UTILITIES

Energy Supply

Via Telefax

October 26, 2000

Mr. Clair Fancy, Chief
Air Regulation
Florida Dept. of Environmental Protection
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station (Facility No. 0010005; ORIS Code: 664)
Combined Cycle No. 1 (PSD-FL-276)
New Unit Notification

Dear Mr. Fancy:

Pursuant to 40 CFR 75.61(a)(2)(i) notification is hereby provided that the new combustion turbine associated with the above-referenced unit is expected to exhaust emissions to the atmosphere on November 27, 2000. If this date changes, notification of the actual date will be provided as required under 40 CFR 75.61(a)(2)(ii).

Please call me at (352) 334-3400 Ext. 1789 or Yolanta Jonynas at Ext. 1284 if you have any questions.

Sincerely,

Darrell R. DuBose
Assistant General Manager of Energy Supply/Designated Representative

xc: D. Beck
M. Costello, FDEP - Tallahassee
J. Jachin, EPA - Region IV
Y. Jonynas
C. Kirts, FDEP - NE District Office, Jax.
R. Klemans
L. Lalwani, FDEP - NE District Branch Office, Gville.
A. Linero, FDEP - Tallahassee
G. Swanson
D. Thompson
JRKCC1

JRKCC140CFR75.61notice.y36

BEST AVAILABLE COPY

Gainesville Regional Utilities 301 SE 4th Avenue (32601) P. O. Box 147117 (A136) Gainesville, FL 32614-7117

To: GRU PSD-FL-276 File

FAX

Date:

Number of pages including cover sheet:

To:
Nancy Clair

Phone:
Fax: 850-922-6979
cc:

From:
Yolanta E. Jonynas

Phone: 352/334-3400 ext. 1284
Fax: 352/334-3151

REMARKS: [ ] Urgent [ ] For your review [ ] Reply ASAP [ ] Please comment
[ ] Per your request

BEST AVAILABLE COPY

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

VIA TELEFAX

May 2, 2000

Mr. Clair Fancy, Chief
Florida Dept. of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station Combined Cycle Unit CC1
DEP File No. 0010005-002-AC
PSD Permit No. PSD-FL-276

Dear Mr. Fancy:

Pursuant to 40 CFR 60.7(a)(1) notice is hereby provided that construction of the above-referenced unit commenced on March 21, 2000.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
C. Heidt
C. Kirts, FDEP- NE District
L. Lalwani, FDEP - NE District Branch Office
G. Swanson
JRK CC1

JRKCC1startconsruc.y35

P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1280 Fax: (352) 334-3151

AL

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

VIA TELEFAX

May 2, 2000

Mr. Clair Fancy, Chief
Florida Dept. of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station Combined Cycle Unit CC1
DEP File No. 0010005-002-AC
PSD Permit No. PSD-FL-276

Dear Mr. Fancy:

Pursuant to 40 CFR 60.7(a)(1) notice is hereby provided that construction of the above-referenced unit commenced on March 21, 2000.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
C. Heidt
C. Kirts, FDEP- NE District
L. Lalwani, FDEP - NE District Branch Office
G. Swanson
JRK CC1

JRKCC1startconsruc.y35

P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1260 Fax: (352) 334-3151

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Michael L. Kurtz, General Manager
City of Gainesville, GRU
Post Office Box 147117
Gainesville, Florida 32614-7117

DEP File No. 0010005-002-AC (PSD-FL-276)
133 MW Repowering Project
Alachua County

Enclosed is the Final Permit Number 0010005-002AC (PSD-FL-276) to construct a combined cycle unit and auxiliary equipment to replace a residual oil and gas-fired steam generator and repower a steam-electrical generator at the Kelly Generating Station in Gainesville, Alachua County. The permit also establishes an enforceable nitrogen oxides emission cap of 133 tons per year for the new unit. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

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 NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2-24-00 to the person(s) listed:

Michael L. Kurtz*
Yolanta Jonynas, GRU
Chair, Alachua County BCC*
Chris Bird, Alachua County EPD
Gregg Worley, EPA
John Bunyak, NPS
Chris Kirts, DEP NED
Kit Reynolds, DEP Gainesville
Tom Davis, P.E., ECT

Clerk Stamp

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

(Clerk) 2-24-00 (Date)

FINAL DETERMINATION

Gainesville Regional Utilities

J.R. Kelly Generating Station
133 MW Repowering Project
PSD-FL-276 and 0010005-002-AC

The Department distributed a public notice package on December 17, 1999 for the project to construct a combined cycle unit to replace a gas and residual oil-fired steam generator and repower a steam turbine-electrical generator at the GRU J.R. Kelly Generating Station in Gainesville, Florida. The Public Notice of Intent to Issue was published in the Gainesville Sun on December 23, 1999. A public meeting was held on January 12, 2000, at the GRU Administration Building, Multi-purpose Room, 303 Southeast 4[st] Avenue in Gainesville, Florida.

EPA and the Fish and Wildlife Service commented adversely on the original application. Their primary comments related to the proposal for Best Available Control Technology (BACT) for the control of nitrogen oxides (NO_X). The comments were mooted by the decision of GRU to take enforceable limitations in annual emissions thus exempting the project from PSD review and BACT for NO_X.

Comments were received from GRU by electronic correspondence on January 21 and February 8. Written comments were received on January 24. Comments related to the Technical Evaluation and Preliminary Determination are acknowledged but no changes will be made, since that document was issued in final form with the Intent to Issue.

Many of GRU's comments on the draft permit and draft BACT determination are minor and are not detailed below. Most of them were incorporated as requested by GRU. Following are the more substantial comments submitted by GRU and the Department's responses.

SECTION II, SPECIFIC CONDITION No. 6:

GRU suggests deletion of reference to federal rule, 40 CFR 52.21, in this condition. GRU states that Florida has an "approved" not "delegated" program. The authority contained in 40 CFR 52.21(r)(2) does not extend to "approved" programs. GRU requests deletion of references to 40CFR52.21(r)(2).

The Department has an obligation to be as consistent as it can be with EPA standards in administering this program. This rule reference will remain as part of this condition. GRU's application states that Projected Actual Date of Commencement of Construction is February 2000 and that Projected Actual Date of Completion of Construction is February 2001. This provision will have no practical effect on GRU.

SPECIFIC CONDITION No. 7

GRU states that Florida has an "approved" not "delegated" program and the authority contained in 40 CFR 52.21(j)(4) does not extend to "approved" programs. Furthermore, the referenced rule applies to phased construction projects. Construction on this project will be continuous (barring unforeseen circumstances). GRU adds that there is no regulatory basis for requiring a BACT re-evaluation upon extension of the permit expiration date especially where construction may already be underway and simply experiencing unforeseen events (e.g., weather or equipment delivery delays) that necessitate extension of the permit. GRU requests that this paragraph should be deleted in its entirety:

The Department has an equivalent rule to 40 CFR 52.21(j)(4) at 62-212.400(6)(b), F.A.C. That Rule specifically references 40 CFR 51.166 (j)(4) which is identical to 40 CFR 52.21(j)(4). The Department's rule and reference to 40 CFR 51.166(j)(4) will replace 40 CFR 52.21(j)(4). The new condition is also consistent with EPA standards.

SPECIFIC CONDITION No. 8

GRU states that the referenced rule in this condition requires that a request (to extend the permit) be made on a "timely" basis (rather than within 30 days). They add that there may be circumstances where the 30 day prior notice may not be possible in every situation. GRU suggests this condition to be modified by adding the word "if possible".

The Department has for many years included a 60 day prior notice for a permit extension request and already changed it to 30 days for this project at the request of GRU. However the Department will make the further change at the request of GRU to 30 days *if possible*. The Department notes that if the permit expires prior to receipt of an extension request, a new application is required.

SECTION III, SPECIFIC CONDITION No. 13

GRU suggests that reference to VOCs be deleted since there does not appear to be a regulatory basis for their inclusion. GRU states that VOCs are not regulated by the Subpart GG NSPS nor were they subject to PSD review. GRU adds that the unit was specified, designed and guaranteed to run well below the applicable NSPS limits and that the manufacturer's recommendations for tuning and maintenance will be geared towards operating the unit as designed and as contractually specified by GRU, notwithstanding the NSPS limits.

The Department concurs with GRU that the VOCs are not regulated by the Subpart GG NSPS and not subject to PSD review. However, for reasonable assurance that the proposed limit will be met, this VOC reference and limit will not be deleted from any condition in the final permit. Only an initial VOC emission test is required for this unit.

SPECIFIC CONDITION No. 15

GRU states that BACT was not triggered for NO_X and the Department has acknowledged that the 9/42 ppmvd at 15% O_2 are vendor guarantees and not emission limitations. GRU affirms that the applicable emission standards are the New Source Performance Standards as set forth in 40 CFR 60, Subpart GG and as adopted by the Department in Rule 62-204.800(7)(b). GRU adds that notwithstanding these limits, the unit has been designed and guaranteed to have emissions significantly lower than the NSPS. Basically, GRU requests replacement of the 9 and 42 ppmvd NO_X limits with the NSPS limits of 97 and 93 ppmvd for this unit.

- If the unit emitted at the NSPS limits, the project would be PSD-significant with an order of magnitude to spare. The project is a synthetically-limited emission unit. As such reasonable assurance is required to preserve this condition. The original application requested 9 ppmvd NO_X and a 24-hour averaging period. The limit together with the longer (720 hours) averaging time provides the Department with reasonable assurance that the annual emission cap will be met. Therefore, the NO_X emission limits will remain as stated in the publicly-noticed permit except for the following minor change in the averaging time: "rolling average" to "block average", "720 hours of operation" instead of "30-day" and "calendar year" instead of "consecutive 365 day". The reference to the rules will also be revised in the final permit.

SPECIFIC CONDITION No. 16

GRU proposes to delete the lb/hr requirement for this pollutant (CO). GRU states that the mass emission rate is provided for informational purposes to simplify the permit and any future potential issues associated with periodic monitoring requirements.

This condition will not be changed as requested by GRU. It is anticipated that it will not be future potential issues associated with periodic monitoring requirements for this pollutant. This pollutant, CO, has gone thorough PSD review and has a BACT limit. BACT emissions limits should be stated in terms of both hourly emissions and pollutant concentration (or obvious technology-based limit. The lb/hr limitations also demonstrate protection of the short term ambient standards. [Refer to Enforceability of BACT – EPA NSR Workshop Manual, October 1990).

SPECIFIC CONDITION NO. 17

GRU suggests that this condition be deleted since there does not appear to be a regulatory basis for it. GRU states that VOCs were not subject to PSD review and that the regulatory reference is not applicable. Also, that VOCs are not regulated under NSPS, Subpart GG.

Refer to response in Specific Condition No. 13. This condition will not be deleted.

SPECIFIC CONDITION No. 19

GRU states that BACT was not triggered for PM and that the mass emission rate (for both PM and PM_{10}) is provided for informational purposes to simplify the permit and any future potential issues associated with periodic monitoring requirements.

The Department will not change this condition as requested. Although VE is a surrogate for PM/PM_{10}, the lb/hr limits (as explained above) ensure enforceability of the short term ambient standard. Recently, EPA has insisted that we PM/PM_{10} lb/hr values in every permit issued for a turbine even if it contains a BACT opacity standard. We are not requiring annual or initial stack test for this pollutant (unless required by Rule 62-297.310(7) F.A.C.). The Department acknowledges that the GRU repowering project was significant only for PM_{10}.

SPECIFIC CONDITION No. 21 (Excess emissions allowed)

GRU requests to delete the 9/42 ppmvd emission limit and substitute the short term standard they proposed in Specific Condition No.15. They affirm that it will be for clarification and permit consistency.

Refer to response to Specific Condition No.15.

SPECIFIC CONDITION No. 22

GRU proposes to delete the sentence " these excess emissions shall be included in the 30-day rolling average (gas) and the 3-hr average (oil) for NO_X from this condition."

This condition will be revised only to the extent of changing the averaging time to be consistent with all related conditions that include an averaging time.

SPECIFIC CONDITION No. 24

According to GRU, it is not clear what constitutes a "substantial modification" of air pollution control equipment. A change of combustors is given as an example but does this refer to a change of all combustors or just one or more combustors? Same type combustors or different ones? Over time, combustion equipment changes/replacements may be necessary but may not necessarily have an impact *on emissions. However, since emission control is integral to the combustion process these could be interpreted to be subject to this requirement. GRU believes this provision should be deleted because it is too subjective and does not have a regulatory basis. To clarify that after the initial CO compliance test, the subsequent annual compliance tests are to be conducted only while burning natural gas. There is no regulatory basis for VOC testing requirements.*

The Department is aware of situations involving other units at other facilities (e.g. the LM6000PA at Lake Cogen) that have exhibited increases in CO emissions following like kind replacements. The fact that there is uncertainty in the ability of the combustors to meet the ultimate CO BACT limit in the first year is justification to require testing following replacement of combustors. Based on the expense of installing new combustors, this is not expected to result in much additional testing. CO tests are very easy and inexpensive to conduct. Regarding the VOC testing requirements, this issue has already been discussed in the responses to Specific Condition No. 13, 15 and 17. GRU's suggestion about the "Year 2" CO compliance language is accepted as proposed. This condition will be modified to reflect the Y2 language suggested.

SPECIFIC CONDITION No. 25

GRU proposes to delete this entire condition related to continuous compliance with the NO_X emissions limits.

The Department believes that reasonable assurance is provided by continuously monitoring NO_X emissions on a continuous basis but with a relatively long averaging period.. The Department will not delete this condition. However, it will be modified to reflect an averaging time (for gas or fuel oil) of 720 operating hours (block basis) instead of 30 days (gas) and 3-hr rolling average (fuel oil). Refer to response in Specific Condition No. 15.

SPECIFIC CONDITION No. 26

GRU proposes to modify this condition stating that the proposed procedures are derived from 40 CFR 75.72 and Appendix F, Section 8.4 and will provide for consistency of data in reporting.

The Department evaluated GRU comments and modified this condition considering some of their concerns. This condition will be modified in the final permit as follows:

Compliance with the NO_X Emission Cap:
Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Annual emissions shall be calculated using the methodology in 40 CFR 75.71 and 75.72 and 40 CFR Part 75, Appendix F, Section 8.4 and shall be reported to the District office on the Annual Operating Report. The owner or operator shall notify the Department as specified in Specific Condition 39 if annual emissions exceed the NO_X cap based on cumulative calculations which are done each month. [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

- For each calendar month or year, NO_X mass emissions (in tons) will be calculated as follows:

  NO_X (in tons) = (Sum of all hourly NO_X mass emissions in lbs for the given time period)/2000

- Condition 39 provides a specific timeframe for reporting if the NO_X cap is exceeded.

SPECIFIC CONDITION No. 29 (Compliance with the VOC emission limit)

GRU proposes to delete this condition. They state that there is no regulatory basis for this requirement.

Refer to responses in Specific Conditions No. 13 and 17

SPECIFIC CONDITION No. 39

GRU proposes various changes related to the use of CEMS for reporting excess emissions. These are primarily related to the 9 and 42 ppmvd time-averaged values for NO_X (gas and fuel oil).

The Department will not change this condition as requested since previous related conditions were not changed either. It will be revised to the extent Specific Conditions Nos. 15 and 21 were revised.

CONCLUSION

The final action of the Department is to issue the permit with the changes described above.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a 102 foot stack for combined cycle operation; a 88 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. The combustion turbine may be equipped with inlet air conditioning devices (e.g., evaporative chillers, foggers, etc.). This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). 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

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; one natural gas-fired conventional boiler designated as Unit 6 (in cold standby); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 6, 7 and 8 have nameplate ratings of 19, 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

ARMS E.U. No.	System	Emission Unit Description
010	Power Generation	Unit CC-1. One dual fuel nominal 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403, Part II, F.S., Electrical Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

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 September 7, 1999
- Department's letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU's letters dated October 25, November 10, December 2 and 16, 1999; January 4 and 24, 2000
- GRU's electronic correspondence dated January 21 and February 8, 2000
- Public Notice Package including Technical Evaluation and Preliminary Determination, December 17, 1999
- Letters from EPA Region IV dated November 10 and January 21, 2000
- Department's Final Determination and BACT determination issued with this Final Permit.

SECTION II - 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 Blair Stone 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 Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.
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 as defined in Rule 62-210.200 F.A.C.. 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. Construction 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. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 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 December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rules 62-4.070(3) and 62-212.400(6)(b), F.A.C., 40 CFR 51.166(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 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.)..
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 Northeast 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 Northeast District and Northeast District Branch Offices 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. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Except as otherwise specified herein (See Specific Condition 39), semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334. Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit 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 when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: 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

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}).

4. Applicable Regulations: 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 (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. 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.]

GENERAL OPERATION REQUIREMENTS

5. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur 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)]

6. Combustion Turbine Capacity: The maximum heat input rates, based on the higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 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)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

8. 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 Northeast District Office and Northeast District Branch 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.]

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the annual nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 F.A.C.]

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for the unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070 F.A.C.]

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, and NO_X, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO, and NO_X, and VOC emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, in accordance with manufacturer's recommendations for emissions control and to comply with the permitted emission limits. [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.].

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

EMISSION LIMITS AND STANDARDS

The following emission limits and standards shall apply upon completion of the initial compliance tests, performance tests and certification tests, as applicable and per pollutant.

15. Nitrogen Oxides (NO_X) Emissions:

- Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 720 operating hour block average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]
- Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 720 operating hour block average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070.(3), F.A.C.]
- Annual Emission Cap: Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Compliance will be demonstrated by the CEMS, as specified in Specific Condition 26. [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070 (3), F.A.C.]

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd. Emissions of CO shall not exceed 54 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
- Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed 43 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial-stack test using EPA Method 18, 25 or 25A. [Rule 62-4.070(3), F.A.C.]

18. 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 up to 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable SO_2 NSPS [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]

19. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, and 62-4.070(3) F.A.C.].

20. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching 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 as follows:

    - During "cold start-up" to combined cycle plant 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.
    - Unless authorized by the Department.

    Excess NOx emissions are defined as one-hour periods when NO_X emissions are above 9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively.

    Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours.

    NO_X CEM data shall be recorded and included in calculating the annual NO_X emissions cap.

    [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These excess emissions shall be included in the 720 operating hour block average for NO_X.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

23. Compliance Time: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1999 version), and adopted by reference in Chapter 62-204.800, F.A.C.

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. 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 change of combustors. Year two (YR2) compliance testing for CO shall be performed in the second year of operation. 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 this 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). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" I and A (YR2 and beyond, gas only).
- 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. Test data shall be corrected to ISO conditions.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

25. Continuous Compliance with the time-averaged NO_X Emission Limits:

- Continuous compliance with the time-averaged NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 720 operating hour block average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 720 operating hour block and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the next 720 operating hour block average. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]
- 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. Valid hourly emission rates shall not include periods of start up, shutdown, fuel switching, or malfunction unless not authorized by 62-210.700 F.A.C. or Specific Condition 21.
- Periods when the 720 operating hour block average or the 133 TPY calendar year cap NO_X exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.

26. Compliance with the NO_X Annual Emission Cap:

Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Annual emissions shall be calculated using the methodology in 40 CFR 75.71 and 40 CFR 75.72 and 40 CFR Part 75, Appendix F, Section 8.4 and shall be reported to the District office on the Annual Operating Report. The owner or operator shall notify the Department as specified in Specific Condition 39 if annual emissions exceed the NO_X cap based on cumulative calculations which are done each month. [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

- For each calendar month or year, NO_X mass emissions (in tons) will be calculated as follows:

  NOx (in tons) = (Sum of all hourly NO_X mass emissions in lbs for the given time period)/2000
- Condition 39 provides a specific timeframe for reporting if the NO_X cap is exceeded.

27. 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) (1999 version). [Applicant request]

28. 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 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. [Rule 62-297.310(7)(a) 4.; Rule62-212.400 and 62-4.070(3) F.A.C.]

29. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.[Rule 62-4.070(3) F.A.C]

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 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 110 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. [Rule 62-297.310(2) F.A.C.]

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices 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). [Rule 62-297.310(7)(a)9 F.A.C and 40 CFR 60.7 and 60.8]

32. 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. [Rule 62-297.310 (7)(b) F.A.C]

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU 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. [Rules 62-4.160(14) and 62-213.440(1)(b)2.,F.A.C]

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

36. Excess Emissions Report: If excess emissions occur (as specified in Condition 21) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast District Branch Offices 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 the format of 40 CFR 60.7, periods of startup, shutdown, fuel switching and malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 15 and 20. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1999 version)].

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): 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. Upon request from EPA or 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. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1999 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The NO_X CEMS shall be used to determine periods of excess emissions. For purpose of reporting, one-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas/fuel oil shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when time-averaged NO_X emissions [i.e., 720 operating hour block average or the annual total (i.e., 133 TPY calendar year)] are above the emission limitations listed in Specific Condition No 15., shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked 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 (1999 version)].

40. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

41. CEMS Certification and Quality Assurance Requirements: 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.

42. Custom Fuel Monitoring Schedule (Natural Gas): Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meets the definitions of pipeline natural gas or natural gas set forth in (40CFR 72). 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 natural gas or pipeline supplied natural gas.
- SO_2 emissions shall be monitored 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 natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

43. Custom 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).

44. 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, weight hoppers, flow meters, and tank scales, pressure gauges, etc., 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].

45. Alternate Methods of Operation: This unit may operate in simple or combined cycle modes.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Combined Cycle Repowering Project

BACKGROUND

The applicant, Gainesville Regional Utilities (GRU), proposes to install a nominal 133 megawatt gas and distillate fuel oil-fired combined cycle unit (Unit CC-1) at the existing J.R. Kelly Generating Station, located near downtown Gainesville, Alachua 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_{10}) and carbon monoxide (CO). 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 Rule 62-212.400, F.A.C.

The primary unit to be installed is a nominal 83 MW General Electric PG7121EA (7EA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) that will feed the existing Unit 8 steam turbine-electrical generator to produce another 40-50 MW. The project will result in the retirement of the conventional gas and residual fuel oil-fired steam generator that presently feeds the Unit 8 steam turbine-electrical generator. The project includes a 102 foot stack for combined cycle operation, and a 88 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 December 18, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on September 7, 1999 and included a BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. The application was revised on December 16, 1999 to reflect a cap on emissions of nitrogen oxides (NO_X).

REVISED BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter (PM_{10})	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs) 10 percent Opacity
Carbon Monoxide	Combustion Controls	25 ppmvd (gas – 1st year) 20 ppmvd (gas – after 1st yr) 20 ppmvd (fuel oil)

According to the revised application, Unit CC-1, will emit approximately 133 tons per year (TPY) of NO_X, 189 TPY of CO (after the first year), 9 TPY of VOC, 47 TPY of SO_2, and 24 TPY of PM/PM_{10}. Because of the shutdown of Unit 8 and an emission cap on NO_X, net emissions increases from the facility are projected to be 39 TPY NO_X, 171 TPY of CO (after the first year), 23 TPY of PM/PM_{10}, 18 TPY of SO_2 and 7 TPY of VOC. The basis for these values is 7,760 hours of operation on natural gas and 1,000 hours on distillate fuel oil.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

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 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). There are no limits for CO or PM_{10} in Subpart GG. PSD was not triggered and a BACT determination is not required for NO_X , SO_2, PM, VOCs, SAM. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY STATES:

The following table is a sample of information on recent CO and PM_{10} BACT or emission limits set by Florida and Southeastern States for General Electric 7EA combustion turbines. The GRU project is included for comparison. The first two projects are for simple cycle installations.

Project Location	CO - ppmvd (or lb/mmBtu)	PM - lb/hr (and/or % opacity)	Technology	Comments
FPC Int. City, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	3x87 MW GE 7EA 12/99 1000 hrs oil
TECO Hardee, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	One 75 MW GE 7EA. 10/99 1000 hrs oil
Olin Cogen, AL	0.07 lb.mmBtu - NG (equals ~ 29 ppmvd))		Clean Fuels Good Combustion	One 80 MW GE 7EA 12/97 DB & PA
GE Plastics Cogen, AL	0.08 lb.mmBtu - NG (equals ~ 33 ppmvd)		Clean Fuels Good Combustion	One 80 MW GE 7EA 5/98 Duct Burner
GRU Gainesville, FL	20 – NG or FO 25 – NG 1st year	5/10 lb/hr - NG/FO 10 percent Opacity	Clean Fuels Good Combustion	One 83 MW GE 7EA Repower 1000 hrs oil

REVIEW OF PARTICULATE MATTER (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 (per the application) will be used for a maximum of 1000 hours per year making any conceivable add-on control technique for PM_{10} either unnecessary or impractical. Annual emissions of PM_{10} are expected to be less than 24.4 tons.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air.

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.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. 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 will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[1]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations are typically permitted to achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. GRU proposes to meet a limit of 20 ppmvd while firing natural gas or fuel oil. GRU requests that it be allowed to initially meet a limit of 25 ppmvd when firing natural gas and to achieve 20 ppmvd after one year. The reason is that GE only offers a guarantee of 25 ppmvd for natural gas on a 7EA unit.

Although GE does not offer a single digit CO guarantee on the 7EA, according to its own reports, CO single-digit emissions have been achieved simultaneously with single-digit NO_X emissions on several MS7001EAs.[2] When the same units are operated at peak power, "expected" CO emissions are 6 ppmvd with an increase of NO_X to 18 ppmvd.

According to recent data reviewed by the Department, actual CO emissions from eight 7E units undergoing conversions to 7EA and DLN-1 technology achieved between 1.3 and 10.5 ppmvd of CO with an average of 5 ppmvd.[3] This was accomplished while the units achieved single-digit NO_X values. The Department expects similar actual performance from the GRU project.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the GRU project assuming full load.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM_{10}, VE	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs)) 10 Percent Opacity
CO	Combustion Controls	25 ppmvd and 54 lb/hr (gas – 1st year) 20 ppmvd and 43 lb/hr (gas – after 1st year) 20 ppmvd and 43 lb/hr (fuel oil)

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The top technology in a top/down analysis for PM_{10} control is good combustion control of inherently clean fuels. No further control methods are available.
- The values of 5 pounds per hour while burning natural gas and 10 lb/hr while burning fuel oil reflect BACT when coupled with a visible emissions limit of 10 percent opacity. The higher 10 lb/hr rate is limited by allowing only 1000 hours of back-up fuel oil use. Most years, fuel oil use will be substantially less than 1000 hours.
- The top technology in a top/down analysis for CO is installation of oxidation catalyst. Use of oxidation catalyst is not widespread except in CO non-attainment areas. It is used in attainment areas when a unit is used that has inherently high emissions of CO.
- GRU's consultant evaluated the use of an oxidation catalyst for the Unit 8 repowering project. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,324,708 with an annualized cost of $345,352 per unit. GRU consultant's estimated levelized costs for CO catalyst control at 2,029 per ton.

- The Department does not necessarily adopt this estimate, but would agree that these estimates would not be cost-effective for removal of CO (especially if emissions without control are actually much lower than 20 ppmvd as discussed above).
- The Department will set CO limits achievable by good combustion at full load as 25 ppmvd (first year of operation) and 20 ppmvd (gas) and 20 ppmvd (oil). These values are equal to those at the recently permitted 7EA units in Florida. They are similar or slightly higher than values from permitted "F" combustion turbines operating in either combined cycle or simple cycle mode. The reason is that the lower firing temperatures of the 7EA units versus the 7FA units results in less burn-out. As discussed above, the Department expects CO emissions to be in the 5 ppmvd range (even when NO_X emissions are 9 ppmvd), but does not want to force a lower guarantee from GE at an excessive cost to GRU.
- 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}.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Particulate (PM_{10})	By VE tests. EPA Method 5 if a special test is needed
Carbon Monoxide	Method 10

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section 2/18
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:

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

2/22/00
Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

2/23/00
Date:

REFERENCES

[1] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[2] Paper. Davis, L.B., GE. Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines. 1998.

[3] Paper. Ihfe, L.M., et. al., Texaco P&G. Kern River and Sycamore Cogen Plant Uprates and Emission Compliance. Power-Gen Conference. New Orleans, Louisiana. November 30, 1999.

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Permitting Application

AIRS ID: 0010005 Site Name: JOHN R KELLY POWER PLANT
Permit #: Type/Subtype: AC/1A Received: 07-SEP-1999
Project #: 002 Project Name: (GRU-KELLY GEN. STATION)

> Receive Request: Done

Event	Begin Date	Prd	Due Date	Rmn	Status	End Date
Receive Request	07-SEP-1999	1	08-SEP-1999		Done	**07-SEP-1999**
Fee Verification	07-SEP-1999	2	09-SEP-1999		Sufficient	09-SEP-1999
Completeness Revie	07-SEP-1999	30	07-OCT-1999		Incomplete	06-OCT-1999
RESET CLOCK	06-OCT-1999	1	07-OCT-1999		Done	06-OCT-1999
Awaiting Addition	06-OCT-1999	45	20-NOV-1999		Received	02-DEC-1999
Completeness Rev	02-DEC-1999	30	01-JAN-2000		Complete	02-DEC-1999
Determine Agenc	02-DEC-1999	90	01-MAR-2000		Issue	17-DEC-1999
Mail Public No	17-DEC-1999	10	27-DEC-1999		Done	17-DEC-1999
Date of Publi	17-DEC-1999	999	11-SEP-2002		Published	23-DEC-1999
Awaiting Pet	23-DEC-1999	14	06-JAN-2000		Not Receiv	06-JAN-2000
Issue Final	06-JAN-2000	14	20-JAN-2000	-27	Pending	

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- 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. Michael Kurtz, Gen. Mgr.
City of Gainesville, GRU
PO Box 147117
Gainesville, Fl
32614-7117

4a. Article Number
Z 031 391 868

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

7. Date of Delivery
0725

GAINESVILLE FL REGISTRY SECT FEB 28 2000 USPS

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

6. Signature: *(Addressee or Agent)*
X Bill Lippencott

Thank you for using Return Receipt Service.

PS Form 3811, December 1994 102595-98-B-0229 Domestic Return Receipt

Feb. 8, 2000 GRU e-mail

PERMITTEE:

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a 102 foot stack for combined cycle operation; a 88 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. The combustion turbine may be equipped with inlet air conditioning devices (e.g., evaporative chillers, foggers, etc.). This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). 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

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; one natural gas-fired conventional boiler designated as Unit 6 (in cold standby); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 6, 7 and 8 have nameplate ratings of 19, 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One dual fuel nominal 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403, Part II, F.S., Electrical Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

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 September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and January 21, 2000

- Department's Final Determination and BACT determination issued with this Final Permit.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION II - 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 Blair Stone 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 Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

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 as defined in Rule 62-210.200 F.A.C.. 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. Construction 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. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 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 December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.070(3) F.A.C., 40 CFR 52.21(j)(4)]

Comment: GRU still believes that there is no regulatory basis for a BACT re-evaluation upon extension of the expiration date of the construction permit.

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 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.)..

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 Northeast 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 Northeast District and Northeast District Branch Offices 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. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Except as otherwise specified herein (See Specific Condition 39), semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334~~, except as otherwise specified herein (See Specific Condition 39)~~. Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

Comment: Specific Condition 39 provides an exception to semi-annual reporting and not to the information required in the report.

SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit 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 when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: 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

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}).

4. Applicable Regulations: 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 (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. 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.]

GENERAL OPERATION REQUIREMENTS

5. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur 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)]

6. Combustion Turbine Capacity: The maximum heat input rates, based on the higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 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)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on

measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

8. 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 Northeast District Office and Northeast District Branch 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.]

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the annual nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 F.A.C.]

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for the unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070 F.A.C.]

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO~~,~~ and NO_X, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO~~,~~ and NO_X, and VOC emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, in accordance with manufacturer's recommendations for emissions control and to comply with the permitted emission limits. [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.].

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

EMISSION LIMITS AND STANDARDS

The following emission limits and standards shall apply upon completion of the initial compliance tests, performance tests and certification tests, as applicable and per pollutant.

15. Nitrogen Oxides (NO_X) Emissions:

- Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 720 operating hour ~~30-day~~ block average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]

Comment: GRU suggests that the block average be specified in terms of the equivalent number of hours in 30 days (i.e., 720) so that averages are calculated based on the same number of hours each time.

- Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 720 operating hour ~~3-hour~~ block average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule ~~62-212.400~~, F.A.C.]

Comment:

- The Dept. has indicated it will accept a consistent averaging time between natural gas and fuel oil combustion.
- GRU suggests that the block average be specified in terms of the equivalent number of operating hours (i.e., 720 hours) in 30 days so that the averages are calculated based on the same number of hours each time.
- NOx was not subject to PSD review - the rule reference is not appropriate.

- Annual Emission Cap: Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. ~~Annual emissions shall be calculated using the methodology in 40 CFR 75 and shall be reported to the District office on the Annual Operating Report. The owner or operator shall immediately notify the Department if annual emissions exceed the NO_X cap based on cumulative calculations which are done each quarter.~~ [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

Comment: Language has been deleted to simplify and clarify the permit. This condition addresses emission limitations. The deleted language is redundant because it is already included in Specific Condition 26, which addresses methodology for calculating annual emissions and reporting requirements.

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd. Emissions of CO shall not exceed 54 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
- Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed 43 lb/hr

(at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule ~~62-212.400~~, F.A.C.]

Comment: VOC's were not subject to PSD - the regulatory reference is not applicable.

18. 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 up to 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable SO_2 NSPS [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]

19. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, reference?, F.A.C.]

Comment: PM was not subject to PSD review - the appropriate regulatory reference should be provided if PM limits are to be included herein. GRU does not believe there is a regulatory basis for inclusion of PM.

20. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed/Excluded from Short-term Limits: Excess emissions resulting from startup, shutdown, fuel switching 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 as follows:

- During "cold start-up" to combined cycle plant 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.
- Unless authorized by the Department.

Excess NOx emissions are defined as one-hour periods when NOx emissions are above 9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively.

Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours.

NO_X CEM data shall be recorded and included in calculating the annual NO_X emissions cap.

[Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

Comment: Suggested language was added for clarification and for consistency with Specific Condition 25.

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These excess emissions shall be included in the 720 operating hour ~~30-day~~ block average ~~(gas) and the 3-hr block average (oil)~~ for NO_X.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

23. Compliance Time: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. 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 change to a different type of combustors. Year two (YR2) compliance testing for CO shall be performed in the second year of operation. 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 this 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). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" I and A (YR2 and beyond, gas only)).
   - 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. Test data shall be corrected to ISO conditions.
   - EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

25. Continuous Compliance with the Short-term NO_X Emission Limits:

   - Continuous compliance with the short-term NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 720 operating hours ~~30-day~~ block average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 720 operating ~~day~~ hours and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the ~~previous 30 days~~ next 720 operating hours. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]
   - ~~Compliance with the NO_x emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour block average basis. Based on CEMS data, a separate compliance~~

~~determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. [Rules 62-4.070(3) F.A.C., 62-210.700, F.A.C., and 40 CFR 75]~~

Comment: The Dept. has indicated it will use the same averaging period for natural gas and fuel oil combustion.

- 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. Valid hourly emission rates shall not include periods of start up, shutdown, fuel switching, or malfunction unless not authorized by 62-210.700 F.A.C. or Specific Condition 21.
- Periods when the ~~30-day block average (gas), 3-hr block average (oil)~~ 720 operating hour block average or the 133 TPY calendar year cap NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.

26. Compliance with the NO_X Annual Emission Cap:

Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Annual emissions shall be calculated using the methodology in 40 CFR 75.72 and Appendix F, Section 8.4 and shall be reported to the District office on the Annual Operating Report. The owner or operator shall ~~immediately~~ notify the Department as specified in Specific Condition 39 if annual emissions exceed the NO_X cap based on cumulative calculations which are done each quarter. [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

Comment:

- In its comments dated January 21, 2000 GRU provided a specific methodology (excerpted from 40 CFR 75) for calculating NOx emissions. Since this was included to clarify the permit conditions for operating personnel, GRU suggests that the language be retained as specified in the referenced comments with the following revision:
  - For each calendar quarter or year, NOx mass emissions (in tons) will be calculated as follows:

    NOx (in tons) = (Sum of all hourly NOx mass emissions in lbs for the given time period)/2000

- Condition 39 provides a specific timeframe for reporting if the NOx cap is exceeded.

27. 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) (1998 version). [Applicant request]

28. 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 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. [Rule 62-297.310(7)(a) 4.; Rule 62-212.400 and 62-4.070(3) F.A.C.]

29. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.[Rule 62-6.070(3) F.A.C]

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 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 110 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. [Rule 62-297.310(2) F.A.C.]

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices 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). [Rule 62-297.310(7)(a)9 F.A.C and 40 CFR 60.7 and 60.8]

32. 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. [Rule 62-297.310 (7)(b) F.A.C]

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU 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. [Rules 62-4.160(14) and 62-213.440(1)(b)2.,F.A.C]

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

36. Excess Emissions Report: If excess emissions occur (as specified in Condition ~~39~~ 21) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast

District Branch Offices 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 the format of 40 CFR 60.7, periods of startup, shutdown, fuel switching and malfunction~~,~~ shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 15 and 20. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1999 version)].

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): 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. Upon request from EPA or 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. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The NOx CEMS shall be used to determine periods of excess emissions. For purposes of reporting, one-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas/fuel oil shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when short-term NO_X emissions [i.e., ~~30-day block average (gas) and 3-hour block average (oil)~~ 720 operating hour block average] or the annual total (i.e., 133 TPY calendar year)] are above the emission limitations listed in Specific Condition No. 15., shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked 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 (1999 version)].

Comment: In order to simplify reporting

40. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

41. CEMS Certification and Quality Assurance Requirements: 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.

42. Custom Fuel Monitoring Schedule (Natural Gas): Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meets the definitions of pipeline natural gas or natural gas set forth in ~~(~~40CFR 72~~)~~. 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 natural gas or pipeline supplied natural gas.
- SO_2 emissions shall be monitored 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 natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

43. Custom 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).

44. 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, weight hoppers, flow meters, and tank scales, pressure gauges, etc., 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].

45. Alternate Methods of Operation: This unit may operate in simple or combined cycle modes.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED
JAN 27 2000
BUREAU OF AIR REGULATION

JAN 21 2000

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for
Gainesville Regional Utility - Kelly Generating Station (PSD-FL-276)
located in Alachua County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for GRU - Kelly Generating Station dated December 17, 1999. The preliminary determination is for the repowering project which will add one combined cycle combustion turbine (CT) with a nominal generating capacity of 83 MW and a 50 MW unfired heat recovery steam generator (HRSG) to be located at the existing J. R. Kelly Generating Station. The project also includes shutting down the existing steam boiler for Unit 8 and routing the HRSG steam to the Unit 8 steam generator. The combustion turbine proposed for the facility is a General Electric (GE), frame 7EA unit. The CT will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CT will be allowed to fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 1,000 hours per year. The draft PSD permit contains a condition which limits the total annual emissions of NO_x from the CT to 133 tons per year and allows GRU - Kelly to avoid PSD review for NO_x. Total net emissions from the proposed project are above the thresholds requiring PSD review for carbon monoxide (CO) and particulate matter (PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we do not have any additional comments beyond those previously submitted during our review of the PSD application. If you have any questions or concerns, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

CC: M. Kurtz, GRU
NED
T. Davis, E&T
P. Reynolds, NEDB

GRU
GAINESVILLE REGIONAL UTILITIES
Strategic Planning

VIA AIRBORNE EXPRESS

January 21, 2000

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 23
Tallahassee, FL 32301

RE: DEP File No. 0010005-002-AC (PSD-FL-276)
J.R. Kelly Generating Station - Combined Cycle Project

Dear Mr. Linero:

Enclosed are Gainesville Regional Utilities' comments on the Draft PSD Permit No. PSD-FL-276, the Best Available Control Technology Determination (BACT) incorporated as Appendix BD and the General Permit Conditions (Appendix GC). GRU's suggested revisions are indicated in red type; rationale for the revisions is indicated in blue.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions or need additional information.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
M. Kurtz
S. Manasco
G. Swanson
JRK CC1

CC1GRUcommentPSD.y33

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

VIA AIRBORNE EXPRESS

January 21, 2000

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Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

RECEIVED
JAN 24 2000
BUREAU OF AIR REGULATION

xc: D. Beck
D. DuBose
M. Kurtz
S. Manasco
G. Swanson
JRK CC1

CC1GRUcommentPSD.y33

P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1260 Fax: (352) 334-3151

PERMITTEE:

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a ~~100~~ 102 foot stack for combined cycle operation; a ~~78~~ 88 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. The combustion turbine may be equipped with inlet air conditioning devices (e.g., evaporative chillers, foggers, etc.). This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

Comment: Stack heights were raised in the final design. Air modelling was conducted using the lower and more conservative heights.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). 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-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; one natural gas-fired conventional boiler designated as Unit 6 (in cold standby); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 6, 7 and 8 have nameplate ratings of 19, 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One ~~nominal~~ dual fuel nominal 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403, Part II, F.S., Electrical Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

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 September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ___?___ 1999

- Department's Final Determination and BACT determination issued with this Final Permit.

SECTION II - 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 Blair Stone 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 Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

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 as defined in Rule 62-210.200 F.A.C.. 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. Construction 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. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C ~~and 40 CFR 52.21(r)(2)~~]

   Comment: Florida has an "approved" not "delegated" program. The authority contained in 40 CFR 52.21(r)(2) does not extend to "approved" programs.

7. ~~BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.070(3) F.A.C., 40 CFR 52.21(j)(4)]~~

   Comments: This paragraph should be deleted in its entirety because:

   - Florida has an "approved" not "delegated" program and the authority contained in 40 CFR 52.21(j)(4) does not extend to "approved" programs. Furthermore, the referenced rule applies to phase construction projects. Construction on this project will be continuous (barring unforeseen circumstances).
   - There is no regulatory basis for requiring a BACT re-evaluation upon extension of the permit expiration date especially where construction may already be underway and simply experiencing

unforeseen events (e.g., weather or equipment delivery delays) that necessitate extension of the permit.

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 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.).

   Comment: The referenced rule requires that a request be made on a "timely" basis. There may be circumstances where the 30 day prior notice may not be possible in every situation.

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 Northeast 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 Northeast District and Northeast District Branch Offices 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. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334, except as otherwise specified herein (See Specific Condition 39). Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit 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 when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: 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

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}).

4. Applicable Regulations: 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 (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. 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.]

GENERAL OPERATION REQUIREMENTS

5. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur 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)]

6. Combustion Turbine Capacity: The maximum heat input rates, based on the ~~H~~higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 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)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on

measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

8. 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 Northeast District Office and Northeast District Branch 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.]

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the annual nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 ~~and 62-210.650~~, F.A.C.]

    Comment: Rule 62-210.650 is redundant - Condition 14 addresses circumvention.

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for ~~each~~ the unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070, ~~and 62-210.650,~~ F.A.C.]

    Comment: Rule 62-210.650 is redundant - Condition 14 addresses circumvention.

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO~~,~~ and NO_X~~, and VOC~~ emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO~~,~~ and NO_X~~, and VOC~~ emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, in accordance with manufacturer's recommendations for emissions control ~~comply with the permitted emission limits.~~ [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.]

Comment:

- VOCs are not regulated by the Subpart GG NSPS nor were they subject to PSD review. GRU suggests that reference to them be deleted since there does not appear to be a regulatory basis for their inclusion.
- The unit was specified, designed and guaranteed to run well-below the applicable NSPS limits. Therefore, the manufacturer's recommendations for tuning and maintenance will be geared towards operating the unit as designed and as contractually specified by GRU, notwithstanding the NSPS limits.

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

EMISSION LIMITS AND STANDARDS

The following emission limits and standards shall apply upon completion of the initial compliance tests, performance tests and certification tests, as applicable and per pollutant.

15. Nitrogen Oxides (NO_X) Emissions:

a) Short-term limits

Nitrogen oxides emissions shall be limited to 97.3/93.0 ppmvd at 15% O2 when firing natural gas and distillate fuel oil, respectively, and when fuel bound nitrogen levels (FBN) are less than or equal to 0.015 percent. For higher fuel bound nitrogen values, the allowance and the adjusted standard shall be determined as follows:

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as defined below:

Fuel-Bound Nitrogen (% by Weight)	F (NO_X % by Volume)
$0 < N \leq 0.015$	0
$0.015 < N < 0.1$	0.04 (N)
$0.1 < N < 0.25$	0.004 + 0.0067(N-0.1)
$N > 0.25$	0.005

where: N= the nitrogen content of the fuel (% by weight)

[Rule 62-204.800(7)(b), F.A.C.]

- ~~Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 30 day rolling average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]~~

- ~~Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 3-hour rolling average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule 62-212.400, F.A.C.]~~

Comment: BACT was not triggered for NOx and the Department has acknowledged that the 9/42 ppmvd at 15% O2 are vendor guarantees and not emission limitations. Therefore, the applicable emission standards are the New Source Performance Standards as set forth in 40 CFR 60, Subpart GG and as adopted by the Department in Rule 62-204.800(7)(b). Notwithstanding these limits, the unit has been designed and guaranteed to have emissions significantly lower than the NSPS.

b) Annual Emission Cap. Total emissions of NO_X shall not exceed 133 tons on a ~~consecutive 365-day~~ calendar year basis~~, rolled daily~~. The annual emission cap shall not be pro-rated if the unit is operated less than 12 months in any calendar year. Compliance will be demonstrated by the CEMS. [Applicant Request to avoid~~, Rule 62-4.070, F.A.C., escape~~ PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

Comment: Language was added for clarification.

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd~~. Emissions of CO shall not exceed~~ (For informational purposes the equivalent emission rate is 54 lb/hr (at ISO conditions)). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

- Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd ~~at 15% O_2 percent oxygen. Emissions of CO shall not exceed~~ (For information purposes the equivalent emission rate is 43 lb/hr (at ISO conditions)). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

Comment: The mass emission rate is provided for informational purposes to simplify the permit and any future potential issues associated with periodic monitoring requirements.

~~17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]~~

Comment: VOCs were not subject to PSD review - the regulatory reference is not applicable. Also, VOCs are not regulated under NSPS, Subpart GG. GRU suggests that this condition be deleted since there does not appear to be a regulatory basis for it.

18. 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 up to 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable SO2 NSPS ~~SO_2~~. [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]

19. Particulate Matter (~~PM/~~PM_{10}) ~~PM/~~ For informational purposes, PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for ~~PM/~~PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

    Comment:

    - BACT was not triggered for PM.
    - The mass emission rate is provided for informational purposes to simplify the permit and any future potential issues associated with periodic monitoring requirements.

20. Visible emissions (VE): VE emissions shall serve as a surrogate for ~~PM/~~PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching 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 as follows:

- During "cold start-up" to combined cycle plant 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.
- Unless authorized by the Department.

    Excess NOx emissions are defined as one-hour periods when NOx emissions are above ~~9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively~~ the short-term standards set forth in Specific Condition 15.a.

    Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours.

    NO_X CEM data shall be recorded and included in calculating the annual NO_X emissions cap.

    [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

    Comment: For clarification and permit consistency.

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup,

shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. ~~These excess emissions shall be included in the 30-day rolling average (gas) and the 3-hr average (oil) for NO_x~~.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

23. Compliance Time: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. ~~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 change of combustors.~~ Year two (YR2) compliance testing for CO shall be performed in the second year of operation. 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 this 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). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (~~YR2 gas only,~~ I and A (YR2 and beyond, gas only)).
- 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. Test data shall be corrected to ISO conditions.
- ~~EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.~~

Comment:

- It is not clear what constitutes a "substantial modification" of air pollution control equipment. A change of combustors is given as an example but does this refer to a change of all combustors or just one or more combustors? Same type combustors or different ones? Over time, combustion equipment changes/replacements may be necessary but may not necessarily have an impact on emissions. However, since emission control is integral to the combustion process these could be interpreted to be subject to this requirement. GRU believes this provision should be deleted because it is too subjective and does not have a regulatory basis.
- To clarify that after the initial CO compliance test, the subsequent annual compliance tests are to be conducted only while burning natural gas.
- There is no regulatory basis for VOC testing requirements.

~~25. 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 30-day rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 30 days. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]~~
- ~~Compliance with the NO_X emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. [Rules 62-4.070(3) F.A.C., 62-210.700, F.A.C., and 40 CFR 75]~~
- ~~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. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless not authorized by 62-210.700 F.A.C.~~
- ~~Periods when the 30-day rolling average (gas), 3-hr average (oil) or the 365-day rolling average NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.~~

Comment: See comment related to Specific Condition 15.

26. Continuous Compliance with the NO_X Emission Cap: NO_X data collected by the certified CEMS shall be used to demonstrate compliance with the ~~365-day rolling~~ annual NO_X emissions cap (specified in Specific Condition 15) ~~for each calendar day of operation~~ by the following method:

- For each hour of operation (including startup and shutdown and fuel switching), the NO_X CEMS shall calculate and record the hourly NO_X mass emissions (in units of pounds per hour, rounded to the nearest tenth of a pound). The hourly mass emissions shall be calculated by multiplying the hourly NOx emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hours). Each hourly emissions rate shall be calculated using at least two valid data points at least 15 minutes apart.
- ~~For each calendar day of operation, the NO_X CEMS shall calculate and record the daily NOx emissions in units of pounds per day, rounded to the nearest tenth of a pound. Daily emissions rates shall be the sum of all recorded hourly emissions rates.~~
- ~~For each calendar day of operation, the NO_X CEMS shall calculate and record the 365-day rolling daily total in units of tons, rounded to the nearest hundredth of a ton. The 365-day rolling total shall be the sum of all recorded daily NO_X emissions rates for the applicable 365 consecutive day period calendar year. NO_X emissions shall be recorded as "zero" for any days occurring prior to initial startup of the combustion turbine.~~
- For each calendar year, NOx mass emissions (in tons) will be calculated as follows:

  NOx (in tons) = (Sum of all hourly NOx mass emissions in lbs)/2000
- When NOx monitoring data is not available, substitution for missing data shall be handled as required by 40 CFR 75.

[Rule 62-4.070(3), F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.]

Comment: These procedures are derived from 40 CFR 75.72 and Appendix F, Section 8.4 and will provide for consistency of data in reporting.

27. 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) (1998 version). [Applicant request]

28. 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. [Regulatory reference ?]

Comment: 40 CFR 75 considers annual testing as once every four successive QA operating quarters (see 40 CFR 75, Appendix B, section 2.3.1.2). A QA operating quarter is defined as a "calendar quarter in which there are at least 168 unit operating hours". Thus, the term "annual" means different things when referencing state compliance testing vs. RATA testing and is potentially confusing.

~~29. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.~~

Comment: There is no regulatory basis for this requirement.

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 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 110 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. [Regulatory reference ?]

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices 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). [Regulatory reference ?]

32. 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. [Regulatory reference ?]

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU 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. [Regulatory reference ?]

35. 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. [Regulatory reference ?]

36. Excess Emissions Report: If excess emissions occur (as specified in Condition 39) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast District Branch Offices 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~~ the format of 40 CFR 60.7, periods of startup, shutdown, fuel switching and malfunction~~,~~ shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 15 ~~through 17~~ and 20. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1999 version)].

Comment: Excess emission reporting would be applicable to NOx and opacity only since they are the pollutants addressed by this permit that will be/could be continuously or periodically monitored without a stack test.

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): 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. Upon request from EPA or 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. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The NOx CEMS ~~NOx~~ shall be used to determine periods of excess emissions. One-hour periods when NOx emissions are above ~~9/42 ppmvd @ 15 % oxygen while firing natural gas and fuel oil , respectively~~ the short-term emission standards specified in Specific Condition 15.a shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when ~~short-term~~ NO_X emissions ~~[i.e., 30-day rolling average (gas) and 3-hour average (oil) or the annual total (i.e., 365-day rolling average)~~ are above the emission limitations listed in Specific Condition No 15. a or b, shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked 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 (1999 version)].

40. CEMS in lieu of Water to Fuel Ratio: ~~Subject to EPA approval, t~~The NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

Comment: EPA approved this proposal by letter from Mr. Doug Neeley (EPA) to Mr. Al Linero (FDEP) dated December 29, 1999.

41. CEMS Certification and Quality Assurance Requirements: 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.

42. Custom Fuel Monitoring Schedule (Natural Gas): ~~Subject to EPA approval,~~ Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meets the definitions of pipeline natural gas or natural gas set forth in ~~(~~40CFR 72~~)~~. 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 natural gas or pipeline supplied natural gas.
- SO_2 emissions shall be monitored 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 natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

Comment: EPA approved the custom fuel monitoring by letter dated from Mr. Doug Neeley (EPA) to Mr. Al Linero (FDEP) dated December 29, 1999.

43. Custom Fuel Oil Monitoring Schedule: ~~Subject to EPA approval, t~~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).

Comment: EPA approved the custom fuel monitoring by letter dated from Mr. Doug Neeley (EPA) to Mr. Al Linero (FDEP) dated December 29, 1999.

44. 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, weight hoppers, flow meters, and tank scales, pressure gauges, etc., 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].

45. Alternate Methods of Operation: This unit may operate in simple or combined cycle modes.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

January 21, 2000
GRU Comments on Appendix BD
Suggested revisions are indicated in red; rationale is provided in blue to the extent it is not already provided in the permit comments.

Gainesville Regional Utilities
J.R. Kelly Generating Station
Combined Cycle Repowering Project

BACKGROUND

The applicant, Gainesville Regional Utilities (GRU), proposes to install a nominal 133 megawatt gas and distillate fuel oil-fired combined cycle unit (Unit CC-1) at the existing J.R. Kelly Generating Station, located near downtown Gainesville, Alachua 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_{10}) and carbon monoxide (CO). 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 Rule 62-212.400, F.A.C.

The primary unit to be installed is a nominal 83 MW General Electric PG7121EA (7EA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) that will feed the existing Unit 8 steam turbine-electrical generator to produce another 40-50 MW. The project will result in the retirement of the conventional gas and residual fuel oil-fired steam generator that presently feeds the Unit 8 steam turbine-electrical generator. The project includes a ~~100~~ 102 foot stack for combined cycle operation, and a ~~78~~ 88 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 December 18, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on September 7, 1999 and included a BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. The application was revised on December 16, 1999 to reflect a cap on emissions of nitrogen oxides (NO_X).

REVISED BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter (PM_{10})	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas)* 10 lb/hr (oil, 1000 hrs)* 10 percent Opacity
Carbon Monoxide	Combustion Controls	25 ppmvd (gas – 1st year) 20 ppmvd (gas – after 1st yr) 20 ppmvd (fuel oil)

- Mass emission rates provided for informational purposes.

According to the revised application, Unit CC-1, will emit approximately 133 tons per year (TPY) of NO_X, 189 TPY of CO (after the first year), 9 TPY of VOC, 47 TPY of SO_2, and 24 TPY of PM/PM_{10}. Because of the shutdown of Unit 8 and an emission cap on NO_X, net emissions increases from the facility are projected to be 39 TPY NO_X, 171 TPY of CO (after the first year), 23 TPY of PM/PM_{10}, 18 TPY of SO_2 and 7 TPY of VOC. The basis for these values is 7,760 hours of operation on natural gas and 1,000 hours on distillate fuel oil.

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.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

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 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). There are no limits for CO or PM_{10} in Subpart GG. PSD was not triggered and a BACT determination is not required for NO_X, ~~or~~ SO_2, PM, VOCs, SAM. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY STATES:

The following table is a sample of information on recent CO and PM_{10} BACT or emission limits set by Florida and Southeastern States for General Electric 7EA combustion turbines. The GRU project is included for comparison. The first two projects are for simple cycle installations.

Project Location	CO - ppmvd (or lb/mmBtu)	PM - lb/hr (and/or % opacity)	Technology	Comments
FPC Int. City, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	3x87 MW GE 7EA 12/99 1000 hrs oil
TECO Hardee, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	One 75 MW GE 7EA. 10/99 1000 hrs oil
Olin Cogen, AL	0.07 lb.mmBtu - NG (equals ~ 29 ppmvd))		Clean Fuels Good Combustion	One 80 MW GE 7EA 12/97 DB & PA
GE Plastics Cogen, AL	0.08 lb.mmBtu - NG (equals ~ 33 ppmvd)		Clean Fuels Good Combustion	One 80 MW GE 7EA 5/98 Duct Burner
GRU Gainesville, FL	20 – NG or FO 25 – NG 1st year	5/10 lb/hr - NG/FO 10 percent Opacity	Clean Fuels Good Combustion	One 83 MW GE 7EA Repower 1000 hrs oil

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 (per the application) will be used for a maximum of 1000 hours per year making any conceivable add-on control technique for ~~PM/~~PM_{10} either unnecessary or impractical. Annual emissions of PM_{10} are expected to be less than 24.4 tons.

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.

Comment: PSD review was triggered for PM10 but not PM. Since this is a BACT review, shouldn't the discussion be limited to PSD pollutants only?

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.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. 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 will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[1]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations are typically permitted to achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. GRU proposes to meet a limit of 20 ppmvd while firing natural gas or fuel oil. GRU requests that it be allowed to initially meet a limit of 25 ppmvd when firing natural gas and to achieve 20 ppmvd after one year. The reason is that GE only offers a guarantee of 25 ppmvd for natural gas on a 7EA unit.

Although GE does not offer a single digit CO guarantee on the 7EA, according to its own reports, CO single-digit emissions have been achieved simultaneously with single-digit NO_X emissions on several MS7001EAs.[2] When the same units are operated at peak power, "expected" CO emissions are 6 ppmvd with an increase of NO_X to 18 ppmvd.

According to recent data reviewed by the Department, actual CO emissions from eight 7E units undergoing conversions to 7EA and DLN-1 technology achieved between 1.3 and 10.5 ppmvd of CO with an average of 5 ppmvd.[3] This was accomplished while the units achieved single-digit NO_X values. The Department expects similar actual performance from the GRU project.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the GRU project assuming full load.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM_{10}, VE	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas)* 10 lb/hr (oil, 1000 hrs)* 10 Percent Opacity
CO	Combustion Controls	25 ppmvd and 54 lb/hr* (gas – 1st year) 20 ppmvd and 43 lb/hr* (gas – after 1st year) 20 ppmvd and 43 lb/hr* (fuel oil)

* Mass emission rates provided for informational purposes.

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The top technology in a top/down analysis for PM_{10} control is good combustion control of inherently clean fuels. No further control methods are available.
- The values of 5 pounds per hour while burning natural gas and 10 lb/hr while burning fuel oil reflect BACT when coupled with a visible emissions limit of 10 percent opacity. The higher 10 lb/hr rate is limited by allowing only 1000 hours of back-up fuel oil use. Most years, fuel oil use will be substantially less than 1000 hours.
- The top technology in a top/down analysis for CO is installation of oxidation catalyst. Use of oxidation catalyst is not widespread except in CO non-attainment areas. It is used in attainment areas when a unit is used that has inherently high emissions of CO.

- GRU's consultant evaluated the use of an oxidation catalyst for the Unit 8 repowering project. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,324,708 with an annualized cost of $345,352 per unit. GRU consultant's estimated levelized costs for CO catalyst control at 2,029 per ton.
- The Department does not necessarily adopt this estimate, but would agree that these estimates would not be cost-effective for removal of CO (especially if emissions without control are actually much lower than 20 ppmvd as discussed above).
- The Department will set CO limits achievable by good combustion at full load as 25 ppmvd (first year of operation) and 20 ppmvd (gas) and 20 ppmvd (oil). These values are equal to those at the recently permitted 7EA units in Florida. They are similar or slightly higher than values from permitted "F" combustion turbines operating in either combined cycle or simple cycle mode. The reason is that the lower firing temperatures of the 7EA units versus the 7FA units results in less burn-out. As discussed above, the Department expects CO emissions to be in the 5 ppmvd range (even when NO_X emissions are 9 ppmvd), but does not want to force a lower guarantee from GE at an excessive cost to GRU.
- 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}.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Particulate (PM_{10})	By VE tests. EPA Method 5 if a special test is needed
Carbon Monoxide	Method 10 ~~(can use RATA if at capacity)~~

Comment: The deleted language conflicts with Specific Condition 28 in the permit and does not appear to be necessary here.

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

[1] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[2] Paper. Davis, L.B., GE. Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines. 1998.

[3] Paper. Ihfe, L.M., et. al., Texaco P&G. Kern River and Sycamore Cogen Plant Uprates and Emission Compliance. Power-Gen Conference. New Orleans, Louisiana. November 30, 1999.

Gentry, Jodi D

From: Dayhaw, Brandi M
Sent: Wednesday, January 19, 2000 2:12 PM
To: Gentry, Jodi D
Subject: New employee orientation

Ken lazzaro will need to reschedule his orientation, he was scheduled to attend on 1/26/00.

Thank you,
Brandi Dayhaw
Gainesville Regional Utilities
dayhawbm@gru.com
(352)334-3400X1148
fax (352)334-3183

should be 141

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.

CO: Convert lb/mmBTU to PPM

0.07	=	lb/mmBTU
20.9	=	Percent oxygen in the air (%)
7.1	=	Percent moisture in exhaust gas (%)
13.9	=	Percent oxygen in exhaust gas (%)
2116.8	=	Atmospheric pressure of 2116.8 lbf/ft2
1465518	=	Volumetric flow rate in actual cubic feet per minute (acfm)
28	=	Molecular Weight (MW) of pollutant, lb/lb-mol
60	=	60 minutes / hour
1545	=	Universal Gas Constant of 1545 ft-lbf/°R
1459	=	Exhaust gas exit temperature in °R (T,°F + 460)
15	=	Correction to 15% oxygen
1000000	=	Conversion from parts per "million"
880	=	mmBTU / hour, HHV

ppmvd @ 15% O2 = [(lb/mmBTU) x (mmBTU/hr) x (1545) x (Temp.) x (20.9 - 15) x (1000000)] / {[(20.9 x (1 - % H2O/100)) - (% O2, actual)] x (2116.8) x (acfm)x (MW) x (60)}

ppmvd @ 15%O2 = 28.5

All parameters based on 100% base load for natural gas firing with inlet air conditions of 59°F and 60% RH.

DIVISIONS OF FLORIDA DEPARTMENT OF STATE
Office of the Secretary
Division of Administrative Services
Division of Corporations
Division of Cultural Affairs
Division of Elections
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RINGLING MUSEUM OF ART

FLORIDA DEPARTMENT OF STATE
Katherine Harris
Secretary of State
DIVISION OF ELECTIONS

RECEIVED
JAN 20 2000
DIVISION OF AIR RESOURCES MANAGEMENT

MEMORANDUM

TO: Florida Administrative Weekly Advertisers

FROM: Liz Cloud, Chief lc
Bureau of Administrative Code

DATE: January 14, 2000

SUBJECT: Invoices for Publications in the Florida Administrative Weekly (FAW)

Please be advised that the invoices for notices printed in the FAW have been revised.

The new invoices are a single sheet with a perforated portion at the bottom of the page, which should be removed and returned with your payment to insure accurate credit to your account. Proof of publication pages will continue to be attached to each invoice.

All invoices should be forwarded to your financial department for payment. Please **do not detach the proof of publication pages from the invoice** before sending it to your financial department for payment. If your office requires more than one copy of the page, please make a copy for your records and send the original to your financial department.

Should you have any questions or problems, please do not hesitate to contact this office.

Thank you.

LC/si

Enclosure

BUREAU OF ADMINISTRATIVE CODE
The Elliot Building • 401 South Monroe Street • Tallahassee, Florida 32399-0250 • (850) 488-8427
FAX: (850) 488-7869 • WWW Address: **http://www.dos.state.fl.us** • E-Mail: *election@mail.dos.state.fl.us*

FLORIDA DEPARTMENT OF STATE
Katherine Harris Secretary of State
Division of Elections
Bureau of Administrative Code
The Elliot Building - 401 South Monroe St. - Tallahassee, Fl. 32399-0250 - (850)488-8427

Billed to:
DEPT OF ENVIRONMENTAL PROTECTION
AIR RESOURCES MANAGEMENT OFFICE
2600 BLAIR STONE ROAD
MAIL STATION 5505
TALLAHASSEE, FL 32399-2400
Attn: SHAROLYN WOOD

Account: 7627 **Invoice Date: 01/14/2000** **Invoice Number: 041519**

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1		Volume:25/52 Pages:5957	28	0.79	$22.12
Invoice # must appear on all checks and correspondence. Please pay balance due:					**$22.12**
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TO INSURE PROPER CREDIT, PLEASE RETURN THIS PORTION.
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The Capitol - Room 1901 - Tallahassee, Fl. 32399-0250

Account: 7627 **Invoice Date: 1/11/00** **Number: 41519** **Amount Due: $22.12**

State Agencies - Journal Transfer to Account Code: 45-50-2-561001-45100000-00
Org Code / EO : 4510-3020 R3 Object: 010000 Category: 001903

For Accounting Use Only: Object Code: 019032 Cat: 001903 ARGL: 16300 GL: 67100

Samas Account Code/Vendor: 37-20-2-035001-37550000-00 calendar days prior to the meeting. If you are hearing or speech impaired, please call the Real Estate Appraisal Board using the Florida Dual Party Relay System which can be reached at 1(800)955-8770 (Voice) and 1(800)955-8771 (TDD).

A copy of the agenda may be obtained by writing: Deputy Clerk, Florida Real Estate Appraisal Board, P. O. Box 1900, Orlando, Florida 32802-1900.

The Florida **Real Estate Appraisal Board** announces a meeting to which everyone is invited.

DATE AND TIME: Tuesday, February 1, 2000, 9:00 a.m.

PLACE: Department of Business & Professional Regulation, Division of Real Estate, Room 301, Third Floor, 400 W. Robinson Street, North Tower, Orlando, FL 32801, (407)245-0800

PURPOSE: Official business of the Appraisal Board. Including but not limited to: Rule/statute amendments, and Disciplinary actions.

Any person who decides to appeal a decision made by the Board with respect to any matter considered at this meeting or hearing will need a record of the proceedings and for such purpose, may need to ensure that a verbatim record of the proceedings is made, which record includes testimony and evidence upon which the appeal is based.

Any person requiring a special accommodation at this meeting because of a disability or physical impairment should contact the Real Estate Appraisal Board, (407)245-0800, at least five calendar days prior to the meeting. If you are hearing or speech impaired, please call the Real Estate Appraisal Board using the Florida Dual Party Relay System which can be reached at 1(800)955-8770 (Voice) and 1(800)955-8771 (TDD).

A copy of the agenda may be obtained by writing: Deputy Clerk, Florida Real Estate Appraisal Board, P. O. Box 1900, Orlando, Florida 32802-1900.

DEPARTMENT OF ENVIRONMENTAL REGULATION

The **Department of Environmental Protection** announces a public meeting to which all persons are invited:

DATE AND TIME: January 12, 2000, 7:00 p.m. – 9:00 p.m.

PLACE: Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to construct a combined cycle combustion turbine-electrical generator at the: Gainesville Regional Utilities, J. R. Kelly Generating Station, 605 Southeast 3rd Street, Gainesville, Alachua County, Florida.

The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Ms. Teresa Heron, Department of Environmental Protection, 2600 Blair Stone Road, MS 5505, Tallahassee, Florida 32399, Telephone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section, (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist, Bureau of Personnel, (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling 1(800)955-8771 (TDD).

DEPARTMENT OF JUVENILE JUSTICE

The **Department of Juvenile Justice** announces a meeting of The Juvenile Justice Standards and Training Commission to which any interested parties are invited.

DATES AND TIMES: January 12, 2000, 1:00 p.m. – 4:30 p.m.; January 13, 2000, 9:00 a.m. – 4:30 p.m.

PLACE: Radisson Hotel, 415 North Monroe Street, Tallahassee, Florida 32301, Telephone (850)224 6000

PURPOSE: Regular meeting to discuss issues related to staff training for Juvenile justice programs, as well as future plans for the juvenile Justice training system.

A copy of the agenda may be obtained after December 31, 1999 by contacting: Peggy Sanders, Florida Department of Juvenile Justice, Office of Staff Development, 2737 Centerview Drive, Suite 114, Tallahassee, Florida 32399-3100, Telephone (850)488-8825.

The **Juvenile Justice Accountability Board** announces a meeting of it's Juvenile Justice Education Policy Task Force which is open to the public.

DATES AND TIME: January 12, 2000, 2:00 p.m.– 6:00 p.m.; January 13, 2000, 8:30 a.m. – 4:00 p.m. or adjournment, whichever is earlier

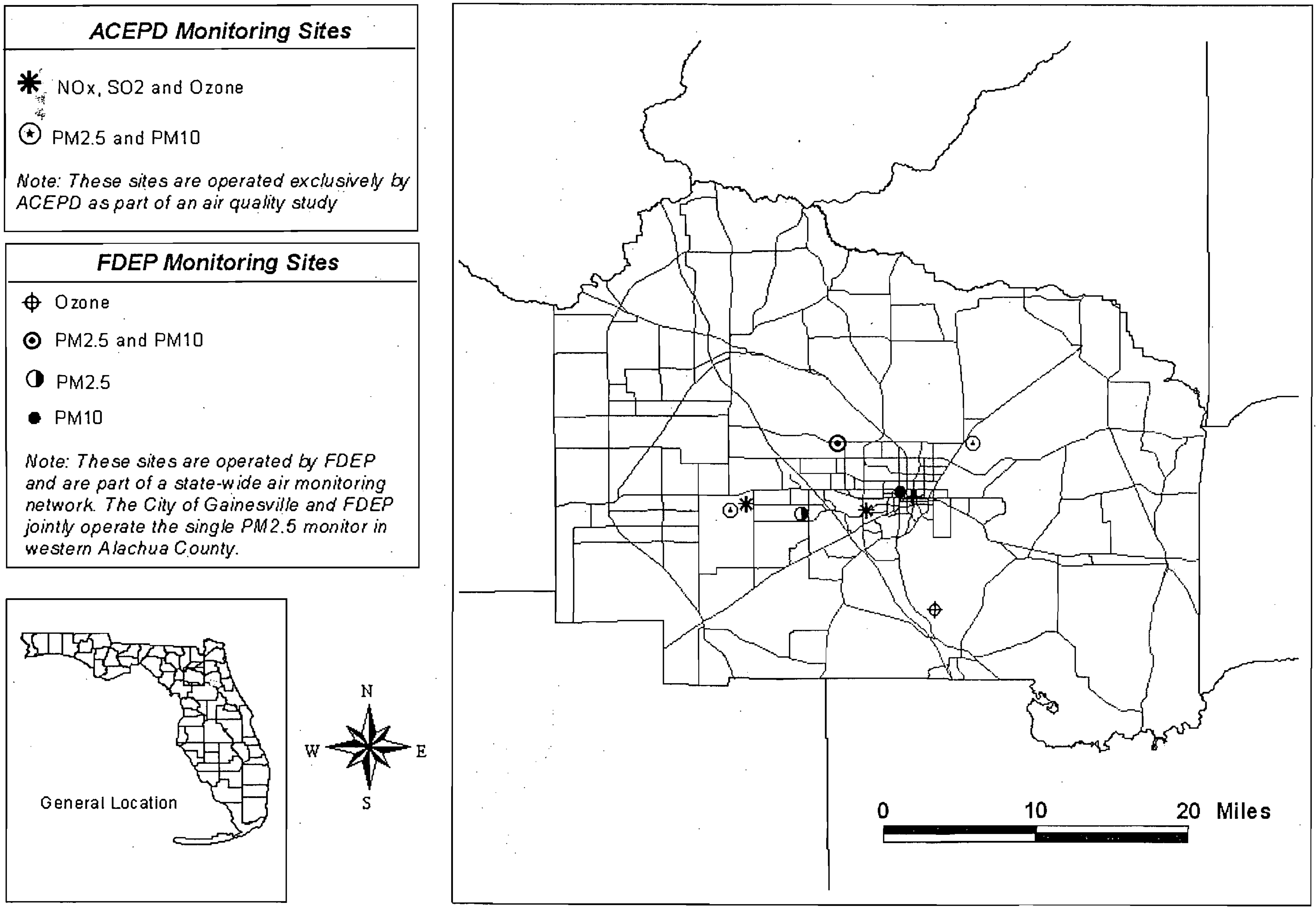
PLACE: Webster Building, Second Floor, Conference Room, 2671 Executive Center Circle, West, Tallahassee, Florida

GENERAL SUBJECT MATTER TO BE CONSIDERED: Includes vocational programming for youth committed to the Department of Juvenile Justice, implementation of Task Force's recommendations in HB 349, school district accountability and funding, and the programmatic, fiscal and governance issues associated with the creation of a separate school district.

For more information, contact: Marianna Tutwiler, Juvenile Justice Accountability Board Office, (850)921-5274.

The **Juvenile Justice Accountability Board** announces a meeting which is open to the public.

Air Quality Monitoring Sites in Alachua County Operated by ACEPD, and FDEP and the City of Gainesville



Sign In Sheet:

name	address
Toni Malone	1901 NW 30 Ter, Gville 32605
[illegible]	10008 SW 67 Dr Gvill 326
	GRU - S. Plng Director

PUBLIC MEETING ANNOUNCEMENT

AGENCY: Florida Department of Environmental Protection

PURPOSE: Receive comments from the public on the Department's proposed air construction permit to be issued to Gainesville Regional Utilities. This permit is for the construction of a new nominal 83-megawatt natural gas and distillate fuel oil fired combustion turbine generator at the existing J.R. Kelly generating Station in Gainesville, Alachua County, Florida.

DATE: January 12, 2000

TIME: 7:00 p.m.

PLACE: GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville.

MEETING AGENDA

7:00 p.m. Introduction/Moderator

- *Clair H. Fancy, P.E., Bureau of Air Regulation, FDEP, Tallahassee*

7:05 p.m. Discussion of Application and air permitting requirements for GRU's proposed new generating unit.

- *A. A. Linero, New Source Review Section, FDEP, Tallahassee.*

7:10 p.m. Discussion of PSD issues and ambient air quality impacts of proposed project.

- *Chris Carlson, Meteorologist FDEP, Tallahassee*

7:15 p.m. FDEP's Draft Best Available Control Technology (BACT) determination for the new plant.

- *A. A. Linero, New Source Review Section, FDEP, Tallahassee*

7:30 p.m. Comments from the public.

9:00 p.m. Adjourn.

DEP AIR PERMITTING SUMMARY SHEET
GRU – COMBINED CYLE UNIT 1
PUBLIC MEETING – ALACHUA COUNTY
JANUARY 12, 2000

GRU proposes to install a new gas-fired Combined Cycle Unit (Unit CC-1) at the J.R. Kelly Generating Station near downtown Gainesville. It will consist of a nominal 83 megawatt (MW) General Electric combustion turbine-electrical generator with an unfired heat recovery steam generator (HRSG). The HRSG will raise sufficient steam to produce approximately another 50 MW via the existing Unit 8 steam turbine-electrical generator. Upon installation of the new proposed unit, the existing Unit 8 boiler will permanently cease operation, though its steam turbine-electrical generator will be retained.

The Florida Department of Environmental Protection (DEP) is the permitting authority for the air construction permit under the provisions of Florida Statutes, the Florida Administrative Code, and our EPA-approved State Implementation Plan per the Code of Federal Regulations.

The DEP received an air permit application and fee on August 9, 1999. The application was updated on December 16 to reflect a cap on emissions of nitrogen oxides. Copies of the application materials were made available to the EPA Region 4 in Atlanta, the U.S. Fish and Wildlife Service Air Quality Branch in Denver, the DEP Northeast District Office in Jacksonville, the DEP Branch Office in Gainesville, and the Alachua County Environmental Protection Department.

The Technical Evaluation and Preliminary Determination and the draft air permit were completed and sent to the applicant along with the Department's Intent to Issue on December 17. Copies were provided to the same agencies as well as to the County Commission.

GRU published the Public Notice of Intent to Issue an Air Construction Permit in The Gainesville Sun December 23. Within the Notice, we advised the venue for this public meeting. We also provided Notice of this public meeting in the Florida Administrative Weekly on December 30.

The Public Notice of Intent provides a 30 day period for anyone to submit comments on the Department's proposed action. It also provided a 14 day period for anyone whose substantial interests were affected by the project to file a petition for an administrative hearing. The period to file a petition ended on January 7 and none was filed.

This meeting will provide the public an opportunity to comment on the proposed permit. Both the application and the Intent to Issue package are still available for public review and copying at the Department's Gainesville, Jacksonville, and Tallahassee offices. We brought with us copies of the key documents in hardcopy versions and on floppy disks in WORD Format. If we run out, we will send copies by mail or e-mail.

The Department will accept comments today and until January 24. In a sense we consider this meeting open until then. We will consider all relevant comments specifically related to air emissions. These public comments as well as those of GRU, Alachua County, EPA and other agencies will be considered in issuing a final permit decision.

Comments may be submitted at this public meeting or sent to:

CONTACT: A. A. Linero, P.E. Administrator
New Source Review Section
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399
Tel: (850)921-9523
Internet: alvaro.linero@dep.state.fl.us

Following is a list of contacts within the Department who can assist with questions regarding air permitting and other matters related to the ~~[illegible]~~ GRU Project:

PUBLIC RECORDS: Kim Tober, Staff Assistant
Bureau of Air Regulation
Tel: (850)921-9533

AIR PERMITTING: Teresa Heron, Engineer
Bureau of Air Regulation, Tallahassee
Tel: (850)921-9529

AIR MODELING: Chris Carlson
Bureau of Air Regulation, Tallahassee
Tel: (850)921-9537

AIR MONITORING: Tammy Eagan
Bureau of Air Monitoring and Mobile Sources
Tel: (850)921-9567

COMPLIANCE: Mort Benjamin
Northeast District Office
Tel: 904/448-4310

LOCAL OFFICE: Pat Reynolds, Manager
NE District/Gainesville Branch Office
Tel: (352)333-2850

LEGAL CONTACT: Doug Beason, Esq.
Office of General Counsel, Tallahassee
Tel: (850)921-9624

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 6, 2000

al

Re: PSD-FL-276

RECEIVED

JAN 12 2000

BUREAU OF AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the additional information regarding the best available control technology (BACT) analysis for Gainesville Regional Utilities' proposed repowering of its J. R. Kelly Generating Station in Gainesville, Florida. The facility is located 102 km south of Okefenokee Wilderness and 103 km northeast of Chassahowitzka Wilderness, both Class I air quality areas administered by the Fish and Wildlife Service. The Air Quality Branch's technical review comments are enclosed. In summary, Gainesville Regional Utilities' additional information for the BACT analysis is incomplete for reasons detailed in the attached technical review document. As the Air Quality Branch's analysis demonstrates, selective catalytic reduction is economically feasible for this project.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

Enclosures

cc: M. Kurtz, GRU
EPA
NED
T. Davis
P. Reynolds, NED Branch

Technical Review of
Addition Information for the Best Available Control Technology Analysis
For Gainesville Regional Utilities
J.R. Kelly Generating Station
PSD-FL-276
Gainesville, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
December 23, 1999

Gainesville Regional Utilities (GRU) is proposing to re-power its existing #8 steam turbine using a General Electric 7EA simple and combined-cycle gas/oil turbine at its J.R. Kelly Generating Station. The facility is located in Gainesville, Florida, 102 km south of Okefenokee Wilderness and 103 km northeast of Chassahowitzka Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service. Nitrogen oxides (NO_x) emissions would be controlled by dry low-NO_x (DLN) combustors when firing natural gas (to 9 parts per million - ppm) and water injection (to 42 ppm) when firing oil. The proposed project will result in Prevention of Significant Deterioration (PSD)-significant increases in emissions of NO_X, fine particulate matter less than 10 microns in diameter (PM-10), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	113
PM-10	23
CO	213

In a September 27, 1999, letter and technical review document, we advised the Florida Department of Environmental Protection that we considered GRU's best available control technology (BACT) analysis to be incomplete because it did not properly evaluate the economic and environmental feasibility of selective catalytic reduction (SCR) and SCONOx™ for control of NO_x emissions.

In a submittal dated October 25, 1999, GRU provided a cost analysis for simple cycle operation. During simple cycle operation, we agree that the proposed NO_x limits represent BACT. However, because this facility may operate in a combined cycle mode, it must also be evaluated under those conditions.

On November 10, 1999, the Environmental Protection Agency (EPA) Region IV provided comments recommending SCR as BACT during combined cycle operation. On the same date, GRU submitted responses to our September 27 comments. Following is our review of GRU's responses.

Best Available Control Technology (BACT) Review

SCONOx™

In their November 10 response, GRU again rejected SCONOx™ control technology as being technically infeasible because "the commercial viability of this technology has not been commercially demonstrated for a comparable size CTG [combustion turbine generator]." We continue to believe that SCONOx™ is now technically feasible based on the permit issued to the La Paloma Power Generating Project. As EPA's New Source Review Workshop Manual states, "a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type." However, if GRU selects SCR as BACT, we would not continue to press this issue.

Selective Catalytic Reduction (SCR)

GRU's revised analysis of SCR was well detailed and supported. However, certain information to support costs is still missing and we disagree with some of GRU's conclusions. Our detailed cost analysis is contained in Table 1. In their revised analysis, GRU again dismissed SCR on the premise that it is not economically feasible and because of purported adverse environmental impacts. Following are our detailed comments:

- GRU did not use a true "top-down" approach because the analysis did not start with the lowest achievable emission rate (LAER). As shown in the enclosed Table 2, LAER should not be greater than 2.5 ppm NO_x for a gas turbine; GRU started at 3.5 ppm. To meet 2.5 ppm, NO_x removal efficiency would need to be increased to 72%. Although we did not estimate the increased catalyst cost that would result from this performance boost, we did estimate the increased ammonia use required for the additional NO_x removal. We recommend that GRU re-evaluate BACT based on meeting a 2.5 ppm NO_x limit and obtain a revised quote from Engelhard (the vendor).

- GRU referred to our omission of the cost for ammonia storage in our previous analysis. Our omission was due to the fact that GRU's initial analysis did not contain this cost and we assumed it was for some good reason.

- We continue to question the need for an additional cost for instrumentation, but have included it for the 72% efficient system we analyzed. We did not apply the EPA 10% instrumentation cost factor to the heat recovery steam generator (HRSG) modification cost component as GRU did because we do not believe that there is any relationship between extending the ductwork and additional instrumentation costs. Furthermore, we request documentation to support the $185,000 estimated for the HRSG modification, and also request that this cost reflect only the addition of SCR and not the CO oxidation catalyst which we believe is unnecessary. (CO is simply not a concern from a stationary source, and there is no value in simply hastening its conversion to carbon dioxide.)

- Please clarify whether Florida allows an exemption from sales taxes for pollution control equipment. If so, then the sales tax cost is extraneous.

- We included the stormwater management costs under "site preparation" but request documentation for this cost, especially if the project "footprint" is reduced by elimination of the CO oxidation catalyst.

- We used a different approach in estimating reagent use, relying upon a "rule of thumb" that it takes 0.6 tons of ammonia to react with one ton of NO_x. This allows for inefficiencies in the reaction and tends to overestimate reagent cost. Our reagent cost is also greater due to the increased NO_x removal.

- We provided a more rigorous analysis of catalyst replacement and disposal costs, but continue to differ with GRU regarding the appropriate Capital Recovery Factor. We continue to believe that the interest rate used to calculate the Capital Recovery Factor should be the 7% value recommended by the EPA OAQPS Control Cost Manual and EPA Region IV in previous correspondence.

- Electricity consumption for ammonia vaporization is greater than GRU's estimate due to the increased NO_x removal.

- The Heat Rate Penalty may be less than the 0.5% recommended by EPA and used by GRU due to the lower (1.5") pressure drop stated by Engelhard. In fact, if the "0.15% penalty per inch of pressure drop" estimate of the Gas Turbine Work Group of the ICCR is used, the Heat Rate Penalty is reduced to 0.225%. The "computational error" mentioned by GRU resulted from our having to guess at the electricity rate used by GRU in its first analysis; such "errors" can be minimized when the applicant provides a clear description of its methods.

- We corrected the Overhead costs and appreciate GRU's catching this error. We are not aware of any computational error in our calculation of Direct Cost; this is probably simply due to a difference in approach.

When we re-calculated the economics of SCR for this application based on the preceding discussion, we estimated a cost of well under $4,000 per ton of NO_x removed. (See enclosed tables.) This essentially confirms our belief that this project would not be subject to any extraordinary costs that would make SCR economically infeasible.

GRU has attempted to equate the reduction in NO_x in ppm to the ammonia slip rate in ppm. Due to the different molecular weights of those two compounds, a comparison of the actual weights of those compounds (Table 1.e.) shows that, while 150 tons of NO_x would be reduced per year, annual ammonia emissions would not exceed 29 tons. If GRU is concerned about the particulate emissions that would result from oil firing, it should consider reducing its proposed use of oil from 1000 hours per year. While we applaud GRU's retirement of Unit #8 and the resulting reduction in emissions, it is still their responsibility to minimize emissions from the new unit.

Environmental impacts have not been shown to be unique or extraordinary. Applicants who propose SCR typically state that the types of "problems" cited by GRU can be prevented by good operation and maintenance practices.

Conclusions and Recommendations

- GRU's BACT analysis is incomplete because it improperly dismissed SCONOx™. However, we are willing to waive that demonstration if SCR is elected.

- GRU's BACT analysis does not demonstrate that the cost of installing and operating SCR would be excessive when compared to other similar proposals. The only "unusual" cost that might be experienced by GRU is related to revisions of the stormwater management system.

- We continue to believe that SCR represents BACT for this application, as demonstrated by our analysis.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Kelly Generating Station
Table 1.a
Plant Data

				Capacity	
Site	FWS Area(s)	Source		(mmBtu/hr)	(MW)
Kelly Station, Gainesville, GA	OKEF	1	CCT	1083	83+40
				each	each

Given/Assumptions

Source	CCT
Exhaust gas flow (lb/Hr)	2,350,008
Exhaust gas flow (acfm)	887,436
Basic Equipment Costs	$710,000
Ammonia storage cost	$50,000
Sales Tax	6%
HSRG Modification	$185,000
Uncontrolled Emission rate (gas--lb/hr)	32.0
Uncontrolled Emission rate (oil--lb/hr)	166.0
Uncontrolled Emission rate (TPY)	208
Control efficiency (%)	72%
Operating Hours per Year (gas)	7,760
Operating Hours per Year (oil)	1,000
Operating Hours per Shift	8
Operating Shifts per Year	1095
Operating Labor Cost ($/hr)	$28.40
Maintenance Labor Cost ($/hr)	$30.61
Electrical Cost ($/kWh)	$0.03
Reagent Use (lb NH3/lb NOx)	0.6
Reagent Costs ($/T)	$102
NH3 Pump& Dilution Air Blower Power (kW)	5
Power to Vaporize NH3 (kW/lb NH3 an)	2
Catalyst replacement	$350,000
Catalyst replacement labor	$40,000
Catalyst disposal ($/T)	$500
Catalyst weight (T)	50.8
Catalyst life (Yr)	5
Heat rate penalty (% of MW output)	0.5%
Ammonia slip (ppm)	5
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Kelly Generating Station

Table 1.b

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item		Factor	Cost
Direct Costs			CCT
Purchased equipment costs			
SCR + auxiliary equipment			$710,000
Ammonia storage			$50,000
Subtotal = A'			$760,000
Instrumentation		0.10 A'	$76,000
HSRG Modification			$185,000
Total = A			$1,021,000
Sales taxes		0.06 A	$61,260
Freight		0.05 A	$51,050
Purchased equipment cost, PEC	B=	1.21 A	$1,133,310
Direct installation costs			
Foundations & supports		0.08 B	$90,665
Handling & erection		0.14 B	$158,663
Electrical		0.04 B	$45,332
Piping		0.02 B	$22,666
Insulation		0.01 B	$11,333
Painting		0.01 B	$11,333
Direct installation costs		0.30 B	$339,993
Site preparation	As required, SP		$100,000
Buildings	As required, Bldg.		$0
Total Direct Costs, DC		1.30 B+SP+Bldg	$1,573,303
Indirect Costs (installation)			
Engineering		0.10 B	$113,331
Construction and field expenses		0.05 B	$56,666
Contractor fees		0.10 B	$113,331
Start-up		0.02 B	$22,666
Performance test		0.01 B	$11,333
Contingencies		0.03 B	$33,999
Total Indirect Cost, IC		0.31 B	$351,326
Total Capital Investment = DC + IC		1.61 B+SP+Bldg	$1,924,629

Kelly Generating Station
Table 1.c
Annual Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor				Cost
Direct Annual Costs, DC					CCT
Operating labor					
Operator	0.5 hr/shift				$15,549
Supervisor	15% of operator				$2,332
Operating materials					
Reagent					
0.6 T NH3/T NOx	208 TPY NOx/0.28 Aqueous NH3*				
		0.72 % control =	321 TPY		
		321 TPY *	102 $/T =		$32,755
Maintenance					
Labor	0.5 hr/shift				$16,759
Material	100% of maintenance labor				$16,759
Catalyst replacement	$350,000 +	6% tax + 5% freight =		$389,550	
labor				40,000.00	
disposal	500 $/T *	50.8 T =		$25,400	
		Total =		$454,950	
	$454,950 * CRF @		0.2439 =		$110,958
Electricity					
NH3 Pump& Dilution Air Blower Power					
5 kW*	0.03 $/kWh*		8,760 hr/yr=		$1,314
Vaporization of aqueous NH3					
2 kW/lbNH3an*0.28lb/NH3/lbNH3*		73.3 lb NH3/hr*			
	0.03 $/kWh*		8,760 hr/yr=		$10,790
Total DC					$207,217
Energy Costs					
Heat rate penalty	83 MW *	8,760 hr/yr *			
	1000 kW/MW *	0.005 loss *	0.03 $/kWh =		$109,062
Indirect Annual Costs, IC					
Overhead	60% of maintenance costs				$30,840
Administrative charges	2% of Total Capital Investment				$38,493
Property tax	1% of Total Capital Investment				$19,246
Insurance	1% of Total Capital Investment				$19,246
Capital recovery	0.1098 * [Total Capital Investment-(1+		0.11)(Cat Cost)]		$197,791
Total IC					$305,616
Total Annual Cost	DC + IC				$621,895

Kelly Generating Station
Table 1.d
Cost Effectiveness

Source	CCT	Units
Pollutant	NOx	
Uncontrolled emissions	208	TPY
Control efficiency	72%	
Controlled emissions	58	TPY
Pollutants removed	150	TPY
Annual cost	$621,895	/yr
Annual cost - Emission fees saved	$617,399	@ $30/T
Cost/ton	$4,150	/T

Kelly Generating Station
Table 1.e
Environmental Impacts of SCR at 72% removal

NOx removed	150 TPY		
Ammonia released	29 TPY @	5 ppmv	

5 ppmvd NOx* E-06 * (20.9/(20.9- 15 % O2)) * 17 MW NH3 * 8740 dscf/mmBtu (fuel input) F-factor(gas)/ 385 scf/lb-mole (vol/mol ratio) = 0.007 lbm/mmBtu

Table 2.a Combined Cycle Gas Turbine Limits from RBLC

Facility Name	Project Description: Simple Cycle	Combined Cycle	Peak Base	Turbine Type	Duct Burner	Power: MW Each	MW Total	mmBtu/hr	HP	Permit #	Permit Issue Date	NOx Emission Limits: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
Alabama Power Company		Y			Y	100	100	353	10566	AL-0115	Dec-97	15.0			
Alabama Pwr--Theodore		Y			Y	170	170			AL-0128	Mar-99	Y		3.5	
American Cogen Tech.											Sep-85			17.0	
Anitec Cogen Plant		Y						451		NY-0061	Jul-93	25.0			
Arrowhead Cogen											Dec-89			9.0	
Baf Energy											Jul-87			9.0	
Bear Island Paper		Y			Y	139	139	474	14172	VA-0190	Oct-92			9.0	15.0
Bear Mountain Limited		Y				48	48			CA-0858	Aug-94			3.6	
Berkshire, MA		Y			N	2*178	272			MA-0022	Sep-97			3.5	9.0
Bermuda Hundred		Y			Y			1175		VA-0184	Mar-92			9.0	15.0
Blue Mtn. Pwr.		Y			Y	153	153	541	16166	PA-0148	Jul-96	Y	Y	4.0	8.4
BMW Manufacturing Corp.		Y						55							
Bridgeport Energy, LLC		Y				260	520			CT-0130	Jun-98			6.0	25.0
Brooklyn Navy Yard Cogen		Y				240	240	848	25358	NY-0044	Jun-95			3.5	10.0
Brush Cogen.		Y			Y			350		CO-0018	May-94	25.0			
Carson Energy Group & Central		Y		2 GE LM6000				450		CA-0812	Jul-93			5.0	
Casco Ray Energy Co.		Y				170	340			ME-0020	Jul-98			3.5	
Champion Int. & Champ. Clean Energy		Y				175	175			ME-0019	Sep-98	9.0	42.0		
Cogen Technologies											**Jun-87**			9.6	
Colorado Power Partnership		Y			Y			385 ea.		CO-0019	May-92	42.0			
Crockett Cogen. - C&H Sugar		Y		GE PG7221 (FA)	Y	240	240			CA-0855	Oct-93			5.0	
Dighton Power Associate, LP		Y				**110**	**175**	**1327**		**MA-0023**	**Oct-97**	Y	Y	Y	Y
Doswell Ltd.											May-90			9.0	
Ecoelectrica		Y				461	461	1629	48709	PR-0004	Oct-96			7.0	9.0
Fleetwood Cogeneration					Y	105	105	360	10764	PA-0099	Apr-94			15.0	
Formosa Plastics		Y				132	132	450	13455	PSD-LA-560	Mar-97	9.0			
Formosa Plastics		Y				*132*	*132*	*450*	*13455*	*PSD-LA-560*	*Mar-95*	*9.0*			
General Electric Plastics		Y			Y			1200		207-0008-X016	May-98				
Gordonsville Energy					Y	445	445	1520	45433	VA-0189	Sep-92			9.0	
Granite Road Limited						135	135	461	13781	CA-0441	May-92			3.5	
Grays Ferry		Y			Y	337	337	1150	34384	PA-0098	Nov-92	9.0			
Hermiston Generating		Y				497	497	1696	50709	OR-0011	Apr-94			4.5	
Hoffman-LA Roche - Nutley Cogen Facility		Y		GE LM500	Y			87			May-95				
Indeck Energy Co.		Y		GE Frame 6	Y			591		563203 0099	May-93	32.0	54.0		
Indeck Oswego Energy Center		Y		GE Frame 6	Y			563		351200 0211 0000	Oct-94	42.0	65.0		
Indeck Yerkes Energy Services		Y		GE Frame 6	Y			452		142400 0133	Jun-92	42.0	65.0		
International Paper		Y						338		PSD-LA-93(M-3)	Feb-94	25.0			
Kamine/Besicorp						190	190	650	19434	2320-00018/00001	Nov-92	9.0		9.0	
Kamine/Besicorp						191	191	653	19524	8-4638-00022/01-0	Nov-92	9.0		9.0	
Kingsburg Energy					Y	35	35	122	3645	CA-0347	Sep-89			6.0	
Lakewood Cogeneration						56	56	190	5681	NJ-0013	Apr-91			9.0	
Las Vegas Cogen											Oct-90			10.0	
Linden Cogeneration		Y				*165*	*165*	*583*	*17434*	*NJ-0011*	*Aug-91*				
Lsp-Cottage Grove						577	577	1970	58901	MN-0022	Mar-95			4.5	
Maui Electric Co. Ltd.		Y	Peak		N	28	28			HI-0013	Dec-91	42.0			
Maui Electric Co. Ltd.		Y	Peak		N	28	28			HI-0015	Jul-92	42.0			
Meak Coated Boards, Inc.		Y			N			568		AL-0096	Mar-97	25.0	42.0		

Table 2.a Combined Cycle Gas Turbine Limits from RBLC

Facility Name	Project Description: Simple Cycle	Project Description: Combined Cycle	Project Description: Peak Base	Project Description: Turbine Type	Project Description: Duct Burner	Power: MW Each	Power: MW Total	Power: mmBtu/hr	Power: HP	Permit #	Permit Issue Date	NOx Emission Limits: Dry Lox-NOx Comb. Gas (ppm)	NOx Emission Limits: Dry Lox-NOx Comb. Oil (ppm)	NOx Emission Limits: SCR Gas (ppm)	NOx Emission Limits: SCR Oil (ppm)
Megan-Racine Associates, Inc.		Y								NY-0057	Aug-89	42.0	65.0		
Mid-Ga. Cogen						116	116	410	12257	GA-0063	Apr-96			9.0	20.0
Narragansett Electric					Y	398	398	1360	40663	RI-0010	Jun-96			9.0	
Nevada Cogen Associates #1		Y		GE LM-2500 (3)	N	3*85	255			NV-0020	Jan-91				
Nevada Cogen Associates #2		Y		GE LM-2500 (3)	N	3*85	255			NV-0018	Jan-91				
Newark Bay Cogen						171	171	585	17491	NJ-0009	Nov-90			8.3	
Newark Bay Cogen						181	181	617	18448	NJ-0017	Jun-93			8.3	16.0
Northern Consolidated Power		Y			Y					PA-0083	May-91	25.0			
Ocean State Power											Dec-88			9.0	
Ols Energy											Jan-86			9.0	
Panda-Kathleen		Y				75	75	265	7925	FL-0102	Jun-95	15.0			
Pasny/Holtsville		Y				336	336	1146	34264	NY-0047	Sep-92	9.0			
Pawtucket Power											Jan-89			9.0	
Pedricktown Cogen						293	293	1000	29899	NJ-0010	Feb-90			9.0	
Pilgrim Energy Center					Y	410	410	1400	41859	NY-0075	Apr-95			4.5	
Portland General Elec.						504	504	1720	51427	OR-0010	May-94			4.5	
PSI Energy Inc. Wabash River Station		Y				192+110	302	1775		IN-0053	May-93				
Richmond Power Enterprise											Dec-89			8.2	
Sacramento Cogen Authority P&G	Y	Y		GE LM6000	N			1263		CA-0810	Aug-94				
Sacramento Power Authority Campbell soup		Y		Siemens V84.2	N			1257		CA-0811	Aug-94				
Sacramento Power Authority Campbell soup		Y		Siemens V84.2	N			1257		CA-0845	Aug-94			3.0	
Saguaro Power Company						35	35	122	3645	NV-0015	Jun-91			9.0	
Santa Rosa Energy LLC		Y		GE 7FA	Y	241	241	585		FL-0116	Dec-98	9.0	9.8		
Saranac Energy Company					Y	329	329	1123	33577	NY-0046	Jul-92			9.0	
Selkirk Cogen					Y	344	344	1173	35072	NY-0045	Jun-92			9.0	
Seminole Fertilizer											Mar-91			9.0	
Seminole Fertilizer Corp						26	26	92	2747	FL-0059	Mar-91			9.0	
Seminole Hardee Unit 3		Y				2*244	488	981	29331	FL-0104	Jan-96	15.0		12.0	
Sepco		Y		GE Model 7	N			920		CA-0813	Oct-94				
Sithe/Independence		Y				625	625	2133	63775		Nov-92			4.5	
South Mississippi Electric Power Association		Y			N			1299		MS-0028	Apr-96				
Sumas Energy											Jun-91			8.0	
Sumas Energy											Dec-90			9.0	
Sumas Energy Inc						88	88	311	9298	WA-0027	Dec-92			6.0	
Sunlaw Cogen		***Y***		***GE LM2500-M-2***	***N***	***28***	***28***			***CA-0863***	***Jan-94***	***2.0***		***9.0***	
SW PSCo						100	100	353	10566	NM-0028	Nov-96	15.0			
SW PSCo						100	100	353	10566	NM-0029	Feb-97	?			
Talahassee		Y				260	260					12.0	42.0		
Tempo Plastics		Y			N					CA-0793	Jan-97	31.0			
Tenaska WA Partners		Y			Y	1	1	2	55	WA-0275	May-92			7.0	
Thermo Industries LTD.		Y			Y			246		CO-0017	Feb-92	25.0			
Tiger Bay						473	473	1615	48281	FL-0072	May-92	15.0			
TNP Techn, LLC		Y		GE LM6000	Y			750		NM-0039	Aug-98			15.0	
Union Carbide Corp.		Y			N	256	256	2023		LA-0096	Sep-95	25.0			
Union Oil											Mar-86			2.5	
University of Medicine & Dentistry of New Jersey		Y			N			168		NJ-0031	Jun-97				
Unocal						0	0			CA-0613	Jul-89			9.0	
Westbrook Power LLC		Y		GE	N	2*264	528			ME-0018	Dec-98			2.5	
Western Power Sys.											Mar-86			9.0	
Willamette Ind.											Apr-85			15.0	
Wyandotte Energy		Y			N	500	500			MI-0244	Feb-99			4.5	

Table 2.b CCT Permits Pending or Not Yet in RBLC

Facility Name/Location	Project Description: Simple Cycle	Combined Cycle	Peak Base	Turbine Type	Duct Burner	Power: MW Each	MW Total	mmBtu/hr	HP	Permit #	Permit Issue Date	NOx Emission Limits: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
AES--Red Oak		Y		GE 7241 (FA)		3*186	558	3 x 1748		NJ					
AES--Red Oak		Y		Siemens Westinghouse 501F	N	4*192	768			NJ				3.5	
Alabama Pwr-Theodore Co-Gen		Y			Y									3.5	
American Electric Co-op		**Y**		**Siemens V84.3A**	**Y**	**268**	**268**							**4.5 / 3**	
Androscoggin Energy		Y			Y	3*50	150	3 x 619		ME				6.0	42.0
ARCO Watson Project						45	45			CA	Oct-97			5.0	
Bridgeport Energy Project														**6.0**	
Calpine--South Point		Y			Y	500	500			AZ		Y		3.0	
Cogen Tech. Linden Venture		**Y**				**581**	**581**	**1983**	**59275**	**NJ**				**3.5**	
Desert Basin Gen		Y						2 x 1940		AZ				4.5	
Dighton, MA										**MA**				**3.5**	
Duke Energy--New Smyrna		Y		GE PG7241FA		2*165	330			FL		12.0			
Enron (LAER)										CA				2.5	
FPC--Hines		Y		W 501Frame		2*165	330			FL				6.0	
FPC--Polk		**Y**				**2*235**	**470**			**FL**					
Frontera Power		Y				330	330			TX		15.0			
Griffith Energy		Y			Y	650	650			AZ				3.0	
HDPP (LAER)										CA				3.0	
Hermiston Generating		Y								CA	Dec-95			4.5	
High Desert Power		Y								CA		9.0		2.5	
Kelly Generating Station															
Kissimmee Utility--Cane Is. #3		Y		GE Frame 7A	Y	167	167			FL		12.0	42.0	6.0	15.0
Lakeland McIntosh CCT		Y				350	350			FL				7.5	15.0
Lake Worth Gen.		Y		GE Frame 7FA		170	170			FL		9.0			
Liberty Electric		Y		GE Frame 7A		2*180	500			PA				3.5	
LaPoloma Generating		Y				4*262	1048			CA				3.0	
Mississippi Pwr--Daniels		Y				170	170			MI		Y		3.5	
Northwest Regional Power		*Y*		*GE Frame 7FA*		*4*210*	*840*	*1530*	*45746*	*WA*		*9.0*			
Osceola Pwr			Peak	GE PG7241 (FA)		3*170	510			FL		10.5	42.0		
Orange Generation--Bartow		Y				2*41	82			FL		15.0			
PSCoNM-Afton		Y		GE Frame 7		140	215	1470		NM		9.0	42.0		
Rotterdam, N.Y.										NY				4.5	
Sacramento Power						115	115			CA	Dec-94			3.0	
Sumas		Y				2*350	700			WA		9.0		4.5	
Sutter						170	170					Y		3.5	
TX-NM Pwr--Lordsburg		Y		aero		2*40	80			NM		15.0	25.0		
Three Mountain Power		Y				500	500			CA				2.5	
Tiverton, RI										RI				3.5	

GRU

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JAN 04 2000

BUREAU OF AIR REGULATION

January 4, 2000

Mr. Clair Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: DEP File No. 0010005-002-AC (PSD-FL-276)
Gainesville Regional Utilities
J.R. Kelly Generating Station - Combined Cycle Project

Dear Mr. Fancy:

Enclosed is a notarized proof of publication of the Public Notice of Intent to Issue Air Construction Permit for the above-referenced project.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
T. Heron, FDEP-Tall
M. Kurtz
A. Linero, FDEP-Tall
S. Manasco
G. Swanson
K. Tober, FDEP-Tall.
JRK CC1

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NO. 17774

THE GAINESVILLE SUN
STATE OF FLORIDA
SUNDAY
COUNTY OF ALACHUA

PUBLISHED DAILY AND
GAINESVILLE, FLORIDA

Before the undersigned authority personally appeared Naomi Williams-Jordan

Who on oath says that he/she is Classified Assistant Manager of THE GAINESVILLE SUN,

a daily newspaper published at Gainesville in Alachua County, Florida, that the attached copy of

advertisement, being a Public Notice of Intent

in the matter of ......

in the ...... Court, was published in said newspaper in the issue of,.

December 23, 1999

Affiant further says that the said THE GAINESVILLE SUN is a newspaper published at Gainesville, in said Alachua County, Florida, and that the said newspaper has heretofore been continuously published in said Alachua County, each day, and has been entered as second class mail matter at the post office in Gainesville, in said Alachua County, Florida, for a period of one year next preceding in the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount for publication in the said newspaper.

Sworn to and subscribed before me this

23 day of Dec. A.D., 19 99

Naomi Williams-Jordan

Sharon K. Williams
(Seal) Notary Public

SHARON K. WILLIAMS
MY COMMISSION # CC 814219
EXPIRES: March 3, 2003
Bonded Thru Notary Public Underwriters

12/30/99

Volume 25, Number 52, December 30, 1999
Notices of Meetings, Workshops and Public Hearings

...previous

Department of Environmental Regulation

The **Department of Environmental Protection** announces a public meeting to which all persons are invited:

DATE AND TIME: January 12, 2000, 7:00 p.m. – 9:00 p.m.

PLACE: Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to construct a combined cycle combustion turbine-electrical generator at the: Gainesville Regional Utilities, J. R. Kelly Generating Station, 605 Southeast 3rd Street, Gainesville, Alachua County, Florida.

The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Ms. Teresa Heron, Department of Environmental Protection, 2600 Blair Stone Road, MS 5505, Tallahassee, Florida 32399, Telephone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section, (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist, Bureau of Personnel, (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling 1(800)955-8771 (TDD).

Department of Juvenile Justice

The **Department of Juvenile Justice** announces a meeting of The Juvenile Justice Standards and Training Commission to which any interested parties are invited.

DATES AND TIMES: January 12, 2000, 1:00 p.m. – 4:30 p.m.; January 13, 2000, 9:00 a.m. – 4:30 p.m.

PLACE: Radisson Hotel, 415 North Monroe Street, Tallahassee, Florida 32301, Telephone (850)224 6000

PURPOSE: Regular meeting to discuss issues related to staff training for Juvenile justice programs, as well as future plans for the juvenile Justice training system.

A copy of the agenda may be obtained after December 31, 1999 by contacting: Peggy Sanders, Florida Department of Juvenile Justice, Office of Staff Development, 2737 Centerview Drive, Suite 114, Tallahassee, Florida 32399-3100, Telephone (850)488-8825.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED
JAN 03 2000
BUREAU OF AIR REGULATION

DEC 29 1999

4APT-ARB

A. A. Linero, P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJECT: Custom Fuel Monitoring Schedule Proposed for Gainesville Regional Utility (GRU) - J. R. Kelly Generating Station located in Alachua County, Florida

Dear Mr. Linero:

This letter is in response to your December 20, 1999, request for approval of a custom fuel monitoring schedule for GRU-Kelly. GRU-Kelly will operate one combined cycle combustion turbine subject to 40 C.F.R. Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. As requested, Specific Conditions 25, 39, 40, 42 and 43 have been reviewed. Additionally, Specific Condition 37 was reviewed. Region 4 has concluded that the use of acid rain nitrogen oxides (NO_X) continuous emission monitoring system (CEMS) for demonstrating compliance, as described in Specific Conditions 25 and 39, is acceptable. The U.S. Environmental Protection Agency (EPA) Region 4 has also concluded that the natural gas custom fuel monitoring schedule proposed in Specific Condition 42 and the fuel oil monitoring schedule described in Specific Condition 43 are both acceptable.

According to 40 C.F.R. 60.334(b)(2), owners and operators of stationary gas turbines subject to Subpart GG are required to monitor fuel nitrogen and sulfur content on a daily basis if a company does not have intermediate bulk storage for its fuel. 40 C.F.R. 60.334(b)(2) also contains provisions allowing owners and operators of turbines that do not have intermediate bulk storage for their fuel to request approval of custom fuel monitoring schedules that require less frequent monitoring of fuel nitrogen and sulfur content.

Region 4 reviewed Specific Condition 42 which allows SO_2 emissions to be quantified using procedures in 40 C.F.R. 75 Appendix D in lieu of daily sampling as required by 40 C.F.R. 60.334(b). Since the specific limitations listed in the permit condition are consistent with previous determinations, we have concluded that the use of this custom fuel monitoring schedule is acceptable.

Specific Conditions 39 and 40 involve the method used to monitor NO_X excess emissions and Specific Condition 25 describes the use of CEMS for demonstrating continuous compliance with the NO_x emission limit. Under the provisions for 40 C.F.R. 60.334(c)(1), the operating parameters used to identify NO_X excess emissions for Subpart GG turbines are water-to-fuel injection rates and fuel nitrogen content. As an alternative to monitoring NO_X excess emissions using these parameters, GRU-Kelly is proposing to use a NO_X CEMS that is certified for measuring NO_X emissions under 40 C.F.R. Part 75. Based upon a determination issued by EPA on March 12, 1993, NO_X CEMS can be used to monitor excess emissions from Subpart GG turbines if a number of conditions specified in the determination are met and included in the permit condition. Additionally, the use of a NO_x CEMS for demonstrating continuous compliance on a 30-day rolling average when firing natural gas and a 3-hour rolling average when firing fuel oil is acceptable.

Specific Condition 37 addresses the potential for correcting results to ISO standard day conditions. The basis for this requirement is that, under the provisions of 40 C.F.R. 60.335(c), NO_x results from performance tests must be converted to ISO standard day conditions. As an alternative to continuously correcting results to ISO standard day conditions, GRU-Kelly plans to keep records of the data needed to make this conversion, so that NO_x results could be calculated on an ISO standard day condition basis anytime at the request of EPA or the Florida DEP. This approach is acceptable, since the construction permit contains NO_x limits that are more stringent than those in Subpart GG, and compliance with Subpart GG for these units would be a concern only in cases when a turbine is in violation of the NO_x limits in its permit.

Finally, Specific Condition 43 addresses the monitoring schedule for fuel oil. According to 40 C.F.R. 60.334(b)(1), the nitrogen and sulfur content of the fuel oil must be monitored each time a new shipment of fuel oil is transferred to bulk storage. GRU-Kelly is proposing to use the fuel analysis provided by the fuel vendor instead of sampling each shipment directly. Provided that all the oil received at the plant complies with the applicable sulfur content limit of 0.8 weight percent, this approach is acceptable, since the specific condition states that the fuel vendor's analyses will comply with the test method requirements of 40 C.F.R. 60.335(d).

If you have any questions about the determination provided in this letter, please contact Ms. Katy R. Forney of my staff at 404-562-9130.

Sincerely yours,

for Gregg M. Worley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

CC: J. Heron, BAR
M. Kurtz, GRU
NPS
NED
T. Davis ECT

GRU GAINESVILLE REGIONAL UTILITIES

December 27, 1999

Mr. Clair Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: DEP File No. 0010005-002-AC (PSD-FL-276)
Gainesville Regional Utilities
J.R. Kelly Generating Station - Combined Cycle Project

Dear Mr. Fancy:

Enclosed is a proof of publication of the Public Notice of Intent to Issue Air Construction Permit for the above-referenced project.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
C. Heidt
T. Heron, FDEP-Tall
R. Klemans
M. Kurtz
A. Linero, FDEP-Tall
S. Manasco
G. Swanson
K. Tober, FDEP-Tall.
JRK CC1

JRKCC1proofofpub1299.y33

Legal Notices

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0010005-002-AC
(PSD-FL-276)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Alachua 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 Gainesville Regional Utilities. The permit is to construct a nominal 83 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine generator at the existing J.R. Kelly Generating Station in downtown Gainesville, Alachua County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM10) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Gainesville Regional Utilities (GRU), Post Office Box 147117, Gainesville, Florida 32614-7717.

The proposed unit (Combined Cycle Unit CC-1) is a General Electric PG7121EA combustion turbine-electrical generator with an unfired heat recovery steam generator that will raise sufficient steam to produce approximately another (maximum) 50MW via the existing Unit 8 steam-driven electrical generator. Upon installation of the new proposed unit, the Unit 8 steam boiler will permanently cease operation. Distillate oil will be used as back up fuel and limited to a 1000 hours per year. The turbine will be able to operate in simple cycle (i.e. without HRSG or steam-electrical turbine). The project also includes: a 78 foot stack for simple cycle operation; a 100 foot stack for combined cycle operation; and a cooling tower (existing).

Emission of PM10 and CO will be controlled by good combustion of clean pipeline supplied natural gas or maximum 0.05 percent sulfur distillate fuel oil. The BACT determination for CO is 20 parts per million by volume (ppmvd). Typical expected CO emissions are 5-10 ppmvd. The BACT determination for PM10 is 5 pounds per hour (lb/hr) while burning natural gas and 10 lb/hr) while burning fuel oil with a visible emission limitation of 10 percent opacity. Nitrogen oxides (NOx) emissions will be controlled by Dry Low NOx technology capable of achieving 9 parts per million by volume (ppmvd) at 15 percent oxygen while firing natural gas and by wet injection achieving 42 ppmvd @ 15% O2 when burning fuel oil. Sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC) will be controlled by good combustion of inherently clean fuels.

PSD and BACT do not apply for NOx, SO2, SAM, PM and VOC emissions. The maximum future potential (i.e., permitted allowable) annual emissions in tons per year are summarized below for comparison with recent past actual annual emissions from Unit 8 which is slated for retirement. The increases shown are based on future potential emissions minus past actual emissions.

Pollutant	Unit 8 (present potential)	Unit 8 (past actual)	CC-1 (future potential)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25
PM10	296	1.8	24.4	22.8	15
SAM	160	1.3	5.4	4.1	7
202	6,498	29	47.1	18	40
NOx	1050	94	133 (cap)	39	40
VOC	12	2	9.2	7	40
CO	78	18	231 (yr 1)	213 (yr 1)	100
CO	78	18	189 (yr 2+)	189 (yr 2+)	100

The modest maximum increases in actual emissions and the very substantial reduction in total potential emissions will accompany a tripling of generation capacity compared with the existing Unit 8 and as much as a six-fold increase in actual power generation. The Department and GRU agreed to an emission cap for Unit CC-1 such that the total NOx increase will be less than 40 TPY and thus exempt from PSD for that pollutant.

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 issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air

Legal Notices

Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice. The Department will hold a public meeting to explain the proposed permitting action and receive public comments. The meeting will be held from 7 to 9 p.m. on January 12, 2000 at the GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue in Gainesville.

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 notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida
904/448-4300
Fax: 904/448-4363

Dept. of Environmental Protection
Northeast District Branch
101 NW 75 Street, Suite 3
Gainesville, Florida 32607
Telephone: 352/333-2850
Fax: 352/333-2856

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.

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Kim Joben

2. MS 5500

3. ____

4. ____

5. ____

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE ____

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

____ FOR YOUR FILES

COMMENTS:

FROM: ____ DATE: ____ PHONE: ____

DEP 15-026 (12/93)

NOTICE OF PUBLIC MEETING

The Department of Environmental Protection announces a public meeting to which all persons are invited:

DATE AND TIME: January 12, 2000 - 7:00 - 9:00 p.m.

PLACE: Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to construct a combined cycle combustion turbine-electrical generator at the Gainesville Regional Utilities J.R. Kelly Generating Station located at 605 Southeast 3rd Street, Gainesville, Alachua County, Florida. The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Ms. Teresa Heron, Department of Environmental Protection at 2600 Blair Stone Road - MS 5505, Tallahassee, Florida 32399, phone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section at (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist in the Bureau of Personnel at (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling (800)955-8771 (TDD).

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

December 20, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Mr. Gregg Worley, Chief
Preconstruction/HAP Section
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
GRU J.R. Kelly Generating Station
Unit 8 Repowering Project, PSD-FL-276

Dear Mr. Neeley:

Attached is another copy for the GRU J.R. Kelly Generating Station Repowering Project in Gainesville, Alachua County. It will be a natural gas-and maximum 0.05 percent sulfur fuel oil-fired combined cycle unit.

The project will trigger PSD for CO and PM_{10}. Please provide your comments on the Draft BACT determination and Draft Permit. The project is not subject to the Florida's Power Plant Siting procedure because it will not increase steam electrical generating capacity. The Department's PSD Rules at 62-212.400., F.A.C. apply.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which meets the requirements of 40 CFR 75 Appendix D Section 2.3.1.4 or by back-up fuel oil with a 0.05% sulfur content. The requirements have been incorporated into the enclosed draft permit as Specific Conditions 42 and 43 and read as follows:

Natural Gas Monitoring Schedule: Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur gas is not required if the vendor documentation indicates that the fuels meet the definitions of natural gas or pipeline natural gas (40CFR 72). 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. (Application received September 7, 1999)

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel natural of gas or pipeline supplied natural gas.
- 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 natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

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).

Please comment on Specific Conditions 25 and 39 which allow the use of the acid rain NO_X CEMS for demonstrating compliance as well as reporting excess emissions, as well as Specific Condition 40 which allows use of CEMS in lieu of measuring the water-to-fuel ratio. Typically NO_X emissions will be less than 10 ppmvd @15% O_2 (gas) which is about one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedules and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Teresa Heron at 850/921-9529.

Sincerely,

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/aal

Enclosures

Z 031 391 906

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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

Sent to Gregg Worley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
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 12-20-99 GRU P50-F1-276	

PS Form **3800**, April 1995

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. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number Z 031 391 906

4b. Service Type

☐ Registered ☑ Certified

☐ Express Mail ☐ Insured

☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)* JOYCE EVANS

6. Signature: *(Addressee or Agent)*

X DEC 22 1999

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

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

PS Form 3811 December 1994 102595-98-B-0229 Domestic Return Receipt

GRU GAINESVILLE REGIONAL UTILITIES

VIA FAX

RECEIVED
DEC 20 1999
BUREAU OF AIR REGULATION

December 16, 1999

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities (GRU)
J.R. Kelly Generating Station - Repowering Project

Dear Mr. Linero:

Pursuant to our discussion related to the above-referenced project, GRU is willing to accept an annual NOx emission cap of 133 tons per year on the proposed combined cycle unit.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
T. Davis, ECT
D. DuBose
T. Heron, FDEP - Tall.
M. Kurtz
E. Regan
G. Swanson
JRK CC1

cc1depnoxcap.y32

Gainesville Regional Utilities 301 SE 4th Avenue (32601) P. O. Box

FAX

Date: 12/17/99

Number of pages including cover sheet: 13

To: Teresa Heron, FDEP

Phone: 850-488-1344

Fax: 850-922-6979

cc:

From:
Yolanta E. Jonynas

Phone: 352/334-3400 ext. 1284

Fax: 352/334-3151

REMARKS: [] Urgent [] For your review [] Reply ASAP [] Please comment [] Per your request

Final suggestions on pre-draft before publication. Plz call me.

Yo

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Units 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 7 and 8 have nameplate ratings of 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following installation of Combined Cycle Unit CC-1.

Teresa - actually # will range from 133-136 depending on fuel. I checked the permit app. [redacted] but it says "nominal"

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One nominal dual fuel 133[redacted]Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

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 September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and ~~Preliminary Determination~~ dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ______ 1999
- Department's Final Determination and BACT determination issued with this Final Permit.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 7 and 8 have nameplate ratings of 25 and 50 MW respectively.

Unit No.8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One nominal dual fuel 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403. Part II, F.S., Electric al Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change. *

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 September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ______ 1999
- Department's Final Determination and BACT determination issued with this Final Permit.

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SECTION II - 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 Blair Stone 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 Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

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 as defined in Rule 62-210.200 F.A.C.. 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. Construction 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. [Rules 62-210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 40 CFR 52.21(r)(2)]

no support in Rules & very punitive in nature

7. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction~~, or extension of the December 31, 2001 permit expiration date,~~ the permittee may be required to demonstrate the adequacy of any previous determination ~~of best~~ available control technology for the source. ~~[Rule 62-4.070(3) F.A.C., 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 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.).

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 Northeast District Office. [Chapter 62-213, F.A.C.]

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SECTION II - ADMINISTRATIVE REQUIREMENTS

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 Northeast District and Northeast District Branch Offices 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. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1999), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334, ~~excess as~~ otherwise specified herein (See Condition 41). Excess emission reports may be submitted on ~~a~~ quarterly basis at the permittee's discretion.

except

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SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit 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 when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: 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

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide and particulate matter smaller than 10 microns.

4. Applicable Regulations: 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 (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. 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.]

GENERAL OPERATION REQUIREMENTS

5. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur 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)]

6. Combustion Turbine Capacity: The maximum heat input rates, based on the ~~Higher~~ h heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 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)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on

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measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

8. 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 Northeast District Office and Northeast District Branch 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.]

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 ~~and 62-[illegible]~~50, F.A.C.]

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for each unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070, ~~and 62-[illegible]~~50, F.A.C.]

13. Combustion Controls: The permittee shall employ "good operating practices" ~~in accordance~~ with the manufacturer's recommended operating procedures to control CO, ~~NO_X, and VOC~~ emissions. Prior to the required initial emissions performance testing, the ~~combustion turbine, the DLN-1~~ combustors, and the control system shall be tuned to comply with the CO, ~~NO_X, and VOC~~ emission limits. Thereafter, these systems shall be maintained ~~and tuned, as necessary,~~ to comply with the permitted emission limits. [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.]

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

VOC + NOx not subject to PSD OR BACT

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SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

EMISSION LIMITS AND STANDARDS

15. Nitrogen Oxides (NO_X) Emissions:

- Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 30-day rolling average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]
- Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 3-hour rolling average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule 62-212.400, F.A.C.]
- Emission Cap. Total emissions of NO_X shall not exceed 133 tons on a ~~consecutive 365-~~ 12-month rolling day basis, rolled daily. Compliance will be demonstrated by the CEMS (annual #/MMBtu x annual heat input) [Rule 62-4.070, F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.]

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd. Emissions of CO shall not exceed 54 lb/hr (at ISO conditions) ~~. Compliance shall~~ to be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
- Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed 43 lb/hr (at ISO conditions) ~~. Compliance shall~~ to be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [~~Rule 62-212.400, F.A.C.~~] VOC ≠ PSD or BACT

18. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be up to 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 content for 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable NSPS SO_2. [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]

19. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

Different font!

20. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching 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 "cold start-up" to combined cycle plant 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.
- Unless authorized by the Department.

Excess emissions are defined as one-hour periods when NOx emissions are above 9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively.

Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours. NO_X CEM data shall be recorded and included in calculating the NO_X emissions cap. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These excess emissions shall be included in the 30-day rolling average (gas) and the 3-hr average (oil) for NO_X.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

23. Compliance Time: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (199~~8~~ 9 version), and adopted by reference in Chapter 62-204.800, F.A.C.

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. 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 change of combustors. Year two (YR2) compliance testing for CO shall be performed in the second year of operation. 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 this unit 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.

as defined under Rule 62-210.200, F.A.C.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A). Annual testing is applicable to fuel oil and only if fuel oil is used for more than 400 hours during the preceding 12-month period.
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (YR2 gas only, I and A) gas only
- 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. Test data shall be corrected to ISO conditions.

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- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

25. Continuous Compliance with the NO_X Emission Limits: when firing natural gas

- Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 30-day rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 30 days. 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. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless not authorized by 62-210.700 F.A.C. [Rules 62-4.070 F.A.C., 62-210.700, fuel switching F.A.C., and 40 CFR 75]
- Compliance with the NO_x emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. 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. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless not authorized by 62-210.700 F.A.C. [Rules 62-4.070(3) F.A.C., 62-210.700, fuel switching F.A.C., and 40 CFR 75]
- Periods when the 30-day rolling average (NG), the 3-hour rolling average (FO), or the ~~365-day~~ 12-month rolling ~~average~~ cap for NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.

26. Continuous Compliance with the NO_X Emission Cap: NO_X data collected by the CEMS shall be used to demonstrate compliance with the ~~365-day~~ 12-month rolling NO_X emissions cap for each calendar day of operation by the following method: (Annual #/MMBtu x annual heat input)

- For each hour of operation (including startup and shutdown), the NO_X CEMS shall calculate and record the hourly NO_X emissions in units of pounds per hour, rounded to the nearest tenth of a pound. Each hourly emissions ~~rate~~ total shall be calculated using at least two valid data points at least 15 minutes apart.
- For each calendar day of operation, the NO_X CEMS shall calculate and record the daily NOx emissions in units of pounds per day, rounded to the nearest tenth of a pound. Daily emissions ~~rates~~ shall be the sum of all recorded hourly emissions ~~rates~~.
- For each calendar day of operation, the NO_X CEMS shall calculate and record the 365-day rolling total in units of tons, rounded to the nearest hundredth of a ton. The 365-day rolling total shall be the sum of all recorded daily NO_X emissions ~~rates~~ for the applicable 365 consecutive day period. NO_X emissions shall be recorded as "zero" for any days occurring prior to initial startup of the combustion turbine. [Rule 62-4.070(3), F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.]

27. 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

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SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

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) (1998 version).

28. 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.

no basis for VOC limit no PSD, no BACT

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

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 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 110 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.

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices 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).

32. 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.

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU 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.

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35. 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.

36. Excess Emissions Report: If excess emissions occur (as specified in Condition 39 ~~40~~) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast District Branch Offices 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. 15 ~~through 17.~~ [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

This section deals w/ malfn. >2hrs. st/stop already addressed in Cond. 21

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): 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. Upon request from EPA or 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. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The CEMS NOx shall be used to determine periods of excess emissions. One-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas and fuel oil, respectively shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when short-term NO_X emissions [i.e., 30-day rolling average (gas), 3-hour average (oil) or the 365 day rolling average] or the annual total (i.e., total of the preceding 12 months) are above the emission limitations listed in Specific Condition No 17, shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked 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 (1999 version)].

40. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

41. CEMS Certification and Quality Assurance Requirements: 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.

42. Custom Fuel Monitoring Schedule (Natural Gas): Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meet the definitions (40CFR 72). 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:

of natural gas or pipeline natural gas

- 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 natural gas or pipeline supplied natural gas.
- SO_2 emissions shall be monitored 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 natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

43. 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).

44. 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

Gainesville Regional Utilities 301 SE 4th Avenue (32601)

Best Available Copy

FAX

Date: 12/17/99

Number of pages including cover sheet: 13

To:
Teresa Heron, FDEP

Phone: 850-488-1344
Fax: 850-922-6979
cc:

From:
Yolanta E. Jonynas

Phone: 352/334-3400 ext. 1284
Fax: 352/334-3151

REMARKS: [ ] Urgent [ ] For your review [ ] Reply ASAP [ ] Please comment
[ ] Per your request

Final suggestions on pre-draft before publication. Plz call me.

Yo

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Units 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 7 and 8 have nameplate ratings of 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following installation of Combined Cycle Unit CC-1.

Teresa - actually it will range from 133-136 depending on fuel. I checked in permit app, but it says "nominal"

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One nominal dual fuel 133 ~~[illegible]~~ Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

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 September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and ~~Preliminary~~ Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ______ 1999
- Department's Final Determination and BACT determination issued with this Final Permit.

BEST AVAILABLE COPY

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 7 and 8 have nameplate ratings of 25 and 50 MW respectively.

Unit No.8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One nominal dual fuel 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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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.

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- Department letter to GRU dated October 6, 1999
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- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ______ 1999
- Department's Final Determination and BACT determination issued with this Final Permit.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION II - 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 Blair Stone 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 Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

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 as defined in Rule 62-210.200 F.A.C.. 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. Construction 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. [Rules 62-210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 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 December 31, 2001 permit expiration date,~~ the permittee may be required to demonstrate the adequacy of any previous determination ~~of best~~ available control technology for the source. ~~[Rule 62-4.070(3) F.A.C., 40 CFR 52.21(j)(4)]~~

no support in Rules & very punitive in nature

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 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.).

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 Northeast District Office. [Chapter 62-213, F.A.C.]

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION II - ADMINISTRATIVE REQUIREMENTS

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 Northeast District and Northeast District Branch Offices 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. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1999), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334, ~~excess~~ as otherwise specified herein (See Condition 41). Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

except

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FAX

Date: 12/16/99

Number of pages including cover sheet: 2

To:
Alvaro Linero, FDEP
√Teresa Heron, FDEP

Phone:
Fax: 850-922-6979
cc:

From:
Yolanta E. Jonynas

Phone: 352/334-3400 ext. 1284
Fax: 352/334-3151

REMARKS: [ ] Urgent [ ] For your review [ ] Reply ASAP [ ] Please comment
[ ] Per your request

This was also sent via E-mail

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GRU GAINESVILLE REGIONAL UTILITIES

VIA FAX

December 16, 1999

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities (GRU)
J.R. Kelly Generating Station - Repowering Project

Dear Mr. Linero:

Pursuant to our discussion related to the above-referenced project, GRU is willing to accept an annual NOx emission cap of 133 tons per year on the proposed combined cycle unit.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
T. Davis, ECT
D. DuBose
T. Heron, FDEP - Tall.
M. Kurtz
E. Regan
G. Swanson
JRK CC1

cc1depnoxcap.y32

Gainesville Regional Utilities 301 SE 4th Avenue (32601) P. O. Box 147117 (A136) Gainesville, FL 32614-7117

Best Available Copy

FAX

Date: 12/14/99

Number of pages including cover sheet: ___

To:
Al Linero

Phone: 850-921-9523
Fax: 850-922-6979
cc:

From:
Yolanta B. Jonynas

Phone: 352/334-3400 ext. 1284
Fax: 352/334-3151

REMARKS: [ ] Urgent [ ] For your review [ ] Reply ASAP [ ] Please comment [ ] Per your request

Preliminary comments:

1. BD-1, BD-5
2. Intent to Issue - pg 2
3. Public Notice - pg 2
4. Tech. Eval & Prelim. Determ. - all pgs.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Combined Cycle Repowering Project

BACKGROUND

The applicant, Gainesville Regional Utilities (GRU), proposes to install a nominal 133 megawatt gas and distillate fuel oil-fired combined cycle unit (Unit CC-1) at the existing J.R. Kelly Generating Station, located near downtown Gainesville, Alachua 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_{10}) and carbon monoxide (CO). 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 Rule 62-212.400, F.A.C.

The primary unit to be installed is a nominal 83 MW General Electric PG7121EA (7EA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) that will feed the existing Unit 8 steam turbine-electrical to produce another 40-50 MW. The project will result in the retirement of the conventional gas and residual fuel oil-fired steam generator that presently feeds the Unit 8 steam turbine-electrical generator. The project includes a 100 foot stack for combined cycle operation, and a 78 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 December 18, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on September 7, 1999 and included a ~~proposed~~ BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. The application was revised on December 16, 1999 to reflect a cap on emissions of nitrogen oxides (NO_X).

REVISED BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs) 10 percent Opacity
Carbon Monoxide	Combustion Controls	25 ppmvd (gas – 1st year) 20 ppm (gas – after 1st yr) 20 ppm (fuel oil)

According to the revised application, Unit CC-1, will emit approximately 133 tons per year (TPY) of NO_X, 189 TPY of CO (after the first year), 9 TPY of VOC, 47 TPY of SO_2, and 24 TPY of PM/PM_{10}. Because of the shutdown of Unit 8 and an emission cap on NO_X, net emissions increases from the facility are projected to be 39 TPY NO_X, 171 TPY of CO (after the first year), 23 TPY of PM/PM_{10}, 18 TPY of SO_2 and 7 TPY of VOC. The basis for these values is 7,760 hours of operation on natural gas and 1,000 hours on distillate fuel oil.

by $1,324,708 with an annualized cost of $345,352 per unit. GRU consultant's estimated levelized costs for CO catalyst control at 2,029 per ton.

- The Department does not necessarily adopt this estimate, but would agree that these estimates would not be cost-effective for removal of CO (especially if emissions without control are actually much lower than 20 ppmvd as discussed above).
- The Department will set CO limits achievable by good combustion at full load as 25 ppmvd (first year of operation) and 20 ppmvd (gas) and 20 ppmvd (oil). These values are equal to those at the recently permitted 7EA units in Florida. They are similar or slightly higher than values from permitted "F" combustion turbines operating in either combined cycle or simple cycle mode. The reason is that the lower firing temperatures of the 7EA units versus the 7FA units results in less burn-out. As discussed above, the Department expects CO emissions to be in the 5 ppmvd range (even when NO_X emissions are 9 ppmvd), but does not want to force a lower guarantee from GE at an excessive cost to GRU.
- 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}.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Particulate (PM_{10})	By VE tests. EPA Method 5 if a special test is needed
Carbon Monoxide	~~Annual~~ Method 10 (can use RATA if at capacity)

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:

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

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

In the Matter of an
Application for Permit by:

Mr. Michael L. Kurtz, General Manager
City of Gainesville, GRU
Post Office Box 147117
Gainesville, Florida 32614-7117

DEP File No. 0010005-002-AC (PSD-FL-276)
Combined Cycle Repowering Project
Alachua County

______________________________/

INTENT TO ISSUE PSD PERMIT

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

The applicant, GRU, applied on September 7, 1999 to the Department for an air construction permit to install a nominal 133 megawatt combined cycle unit and auxiliary equipment and to ~~dismantle~~ retire the conventional boiler presently providing steam to the Unit 8 steam turbine-electrical generator at the J. R. Kelly Generating Station near downtown, Gainesville, Alachua County.

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

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

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

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

The Department will accept written comments ~~meetings~~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 Air 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. The Department will hold a public meeting to explain the proposed permitting action and receive public comments on January ~~15~~ 18, 2000 at the ~~County Commission Chambers, etc.etc.etc.~~ Gainesville Regional Utilities Administration Building Multipurpose Room at 301 SE 4th Ave, Gainesville, FL from 7:00 - 9:00 PM.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Alachua 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 Gainesville Regional Utilities. The permit is to construct an 83 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine generator at the existing J.R. Kelly Generating Station in downtown Gainesville, Alachua County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM$_{10}$) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Gainesville Regional Utilities (GRU), Post Office Box 147117, Gainesville, Florida 32614-7717.

The proposed unit (Combined Cycle Unit CC-1) is a General Electric PG7121EA combustion turbine-electrical generator with an unfired heat recovery steam generator that will raise sufficient steam to produce approximately another (maximum) 50 MW via the existing Unit 8 steam-driven electrical generator. Upon commencement of commercial operation of the new proposed unit, the Unit 8 steam boiler will permanently cease operation. Distillate oil will be used as back up fuel and limited to a 1000 hours per year. The turbine will able to operate in simple cycle (i.e. without HRSG or steam-electrical turbine). The project also includes: a 78 foot stack for simple cycle operation; a 100 foot stack for combined cycle operation; a cooling tower ~~for pond water~~ (existing) ~~and a small heater to heat the natural gas prior to use in simple-cycle operation~~. and

pipeline

Emissions of PM$_{10}$ and CO will be controlled by good combustion of clean natural gas or maximum 0.05 percent sulfur distillate fuel oil. The BACT determination for CO is 20 parts per million by volume (ppmvd). Typical expected CO emissions are 5-10 ppmvd. The BACT determination for PM$_{10}$ is 5 pounds per hour (lb/hr) while burning natural gas and 10 lb/hr) while burning fuel oil with a visible emission limitation of 10 percent opacity. Nitrogen oxides (NO$_X$) emissions will be controlled by Dry Low NO$_X$ technology capable of achieving 9 parts per million (ppmvd) by volume at 15 percent oxygen while firing natural gas and by wet injection achieving 42 ppmvd @15% O_2 when burning fuel oil. Sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC) will be controlled by good combustion of inherently clean fuels. ~~When firing fuel oil, the NO$_x$ emissions will be limited to 42 ppmvd at 15% O$_2$ by wet injection.~~ (redundant

PSD and BACT do not apply for NO$_X$, SO_2, SAM, PM and VOC emissions. The maximum future potential (i.e. permitted allowable) annual emissions in tons per year are summarized below for comparison with recent past actual annual emissions from Unit 8 which is slated for retirement. The increases shown are based on future potential emissions minus past actual emissions.

Pollutant	Unit 8 (present potential)	Unit 8 (past actual)	CC-1 (future potential)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25
PM$_{10}$	296	1.8	24.4	22.6	15
SAM	160	1.3	5.4	4.1	7
SO_2	6,498	29	47.1	18	40
NO$_x$	1050	94	133 (cap)	39	40
VOC	12	2	9.2	7	40
CO	78	18	231 (yr 1)	213 (yr 1)	100
CO	78	18	189 (yr 2+)	171 (yr 2+)	100

The modest maximum increases in actual emissions and the very substantial reduction in total potential emissions will accompany a tripling of generation capacity compared with the existing Unit 8 and as much as a six-fold increase in actual power generation. The Department and GRU agreed to an emission cap for Unit CC-1 such that the total NO$_X$ increase will be less than 40 TPY and thus exempt from PSD for that pollutant. ~~This insures that a selective catalytic reduction system using vanadium pentoxide catalyst and ammonia injection is not needed.~~

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 issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments

Environmental Consulting & Technology, Inc.

RECEIVED
DEC 03 1999
BUREAU OF AIR REGULATION

December 2, 1999
ECT No. 990100-0200

SENT BY FAX AND OVERNIGHT MAIL ON 12/2/99

Mr. Jim Little
U.S. Environmental Protection Agency
Region 4
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division
Atlanta Federal Center
61 Forsyth Street, S.W.
Atlanta, GA 30303-8960

Re: PSD Application for Gainesville Regional Utilities – Kelly Generating Station (PSD-FL-276) Located in Alachua County, Florida

Dear Mr. Little:

On behalf of the City of Gainesville, Gainesville Regional Utilities (GRU), the following responses to comments provided by the U.S. Environmental Protection Agency (USEPA) to the Florida Department of Environmental Protection (FDEP) in correspondence dated November 10, 1999 are submitted for your consideration:

1. *Region 4 has evaluated the SCR cost assessments prepared by the applicant and the U.S. Fish and Wildlife Service. We have also given consideration to the concerns about the accidental release risks and potential environmental impacts of ammonia handling. Our conclusion following this review is that use of SCR combined with a DLN combustor should be considered BACT for NO_x emissions when the proposed facility is operated in combined cycle mode firing natural gas.*

Response

A detailed response to the U.S. Fish and Wildlife Service (USFWS) comments regarding the economic and environmental impacts of SCR technology for the J.R. Kelly Repowering Project were provided to the FDEP in correspondence from Environmental Consulting & Technology, Inc. (ECT) dated November 10, 1999. FDEP has advised GRU that a copy of this response has been provided to the USEPA, Region 4. The response to the USFWS comments also addresses the SCR issues raised by the USEPA.

The J.R. Kelly Repowering Project is unique in comparison to other recent combustion turbine power projects in that a contemporaneous decrease of 94 tons per year (tpy) of NO_x emissions will occur as a result of the repowering project. Actual NO_x emissions

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from existing Unit 8, which will cease operations following the installation and operation of the new CT/HRSG unit, averaged 94.1 tpy during 1997 and 1998. The substantial difference in net emission rates for repowering and grass roots CT projects is an important factor which should be considered in BACT determinations for these two types of power projects.

With the inclusion of the emissions decrease associated with the shutdown of existing Unit 8, the NO_x exhaust concentration from the J.R. Kelly Generating Station Repowering Project CT/HRSG unit during gas-firing is equivalent to a grass-roots GE 7EA CT/HRSG unit achieving 2.2 ppmvd NO_x. Therefore, the *net* increase in NO_x emissions from the repowering project is equivalent to a grass roots CT with NO_x emissions *lower* than the USEPA suggested SCR controlled level of 3.5 ppmvd. If GRU had not elected to repower existing Unit 8 but rather simply added a new CT/HRSG unit equipped with SCR controls (a scenario that would meet with regulatory agency approval), net facility NO_x emissions would be *greater* than that proposed for the repowering project.

In addition to the repowering aspects, use of SCR is not considered to represent BACT for NO_x for the following reasons:

- Operation of a SCR control system will result in an ammonia slip exhaust concentration of 5 ppmvd. This concentration is approximately equal to the NO_x concentration reduction (i.e., 5.5 ppmvd) resulting from the application of SCR control technology. At baseload operations and 59°F, a 5 ppmvd ammonia slip concentration will result in ammonia emissions of approximately 30 tpy. The excess ammonia would also be available to react with SO_3 contained in the CT/HRSG exhaust stream; $PM_{2.5}$ emissions would increase, and PM/PM_{10} emissions during oil-firing would approximately double.

- Aqueous ammonia is a designated an *extremely hazardous chemical* which is regulated extensively due to its toxicity. The regulation of aqueous ammonia under 40 CFR Part 68 Chemical Accident Prevention Provisions demonstrates that transportation, handling, and storage of aqueous ammonia are activities that, in the judgement of the EPA, may potentially result in the accidental release of a toxic chemical. The potential for accidental releases of aqueous ammonia in an urban setting with significant public exposure poses an unnecessary public health risk, particularly in light of the minimal environmental benefits that may occur due to its use for the J.R. Kelly Generating Station Repowering Project.

- Maximum annual NO_2 air quality impacts due to operation of the new CT/HRSG unit during oil-firing, without a SCR control system, are projected to be only 0.2 percent of the NAAQS for this air contaminant. During the predominant gas-firing mode of operation, maximum annual NO_2 air quality impacts, without a SCR control system, are projected to be only 0.01 percent of the NAAQS. These already low air quality impacts show that the addition of a SCR control system will provide no discernable improvement in NO_2 ambient air quality.

- The application of CT dry low-NO_x (DLN) control technology represents pollution prevention in that the technology prevents the creation of an air contaminant by means of process combustion modifications. Pollution prevention technology achieving comparable emission reductions is considered environmentally superior to add-on controls because lower quantities of solid wastes, wastewater, and collateral air emissions are generated compared to add-on controls. The regulatory definition of BACT specifically includes *innovative combustion techniques* as a control technology which can be considered in a BACT analysis. DLN technology would clearly qualify as an innovative combustion technique. The history of DLN development leads to the conclusion that future improvements in performance (i.e., lower NO_x emissions) are likely to occur. Due to the significant economic costs and collateral air emissions associated with add-on control systems such as SCR, further encouragement by the regulatory agencies of improved DLN performance is considered desirable. Mandating SCR control systems for CTs that achieve single digit NO_x exhaust concentrations would likely do the opposite by reducing the incentive to further refine and improve DLN technology. Regulatory encouragement of further improvement in DLN technology would also prove environmentally beneficial with respect to reducing NO_x emissions from simple-cycle CTs since these units generally do not have the option of using SCR control technology due to temperature and economic considerations.

For the above reasons, GRU requests that USEPA reconsider their conclusions regarding NO_x BACT for the J.R. Kelly Generating Station Repowering Project.

2.	*The proposed BACT for particulate matter (PM_{10}) is 10% opacity for visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT particulate matter emissions rate limit. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions should also list the corresponding emission rate for particulate matter (i.e., 9 lb/hr for natural gas, 17 lb/hr for fuel oil.)*

<u>Response</u>

GRU concurs with this comment.

3.	*It is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions.*

Response

An exemption from excess emissions was requested due to startup, shutdown, fuel switching, or malfunction because the CT vendor emission performance levels can not be achieved during these periods. During cold and warm startups, temperatures within the HRSG must be increased slowly to avoid metallurgical damage. Accordingly, the CT must be operated at low load for a period of time to properly acclimate the HRSG to the hot CT exhaust gas stream. During these low load startup periods, CT emissions will exceed the vendor performance guarantees. A similar situation arises during CT/HRSG shutdowns. Accordingly, an exemption from excess emissions due to startup, shutdown, fuel switching, or malfunction is considered appropriate and necessary.

Your further consideration of the NO_x BACT issues concerning GRU's J.R. Kelly Repowering Project will be appreciated. If you have any questions, please feel free to give me a call at 352/332-6230, Ext. 351.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

cc: Ms. Theresa Heron, FDEP ✓
Ms. Yolanta Jonynas, GRU

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Environmental Consulting & Technology, Inc.

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4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: PSD Application for Gainesville Regional Utility - Kelly Generating Station
(PSD-FL-276) located in Alachua County, Florida

Dear Mr. Linero:

Thank you for sending the PSD permit application dated September 8, 1999, for the above referenced facility. The application is for the repowering project which will add one simple/combined cycle combustion turbine (CT) with a nominal generating capacity of 83 MW and a 50 MW unfired heat recovery steam generator (HRSG) to be located at the existing J. R. Kelly Generating Station. The project also includes shutting down the existing steam boiler for Unit 8 and routing the HRSG steam to the Unit 8 electric generator. The combustion turbine proposed for the facility is a General Electric (GE), frame 7EA unit. The CT will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CT will be allowed to fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 1,000 hours per year. Total net emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM_{10}).

Based on our review of the PSD permit application, we have the following comments:

1. The applicant proposed a best available control technology (BACT) NO_x emission limit of 9 ppmvd (15% oxygen) for natural gas firing to be achieved by use of dry low-NO_x combustion. The proposed BACT for NO_x emissions when firing No. 2 fuel oil is 42 ppmvd using water injection. The applicant preformed a cost analysis which considered using selective catalytic reduction (SCR) to control NO_x emissions from the CT. The applicant's cost analysis calculated the cost effectiveness of SCR to be $5,027/ton removed of NO_x. The U.S. Fish and Wildlife Service disagreed with some of the assumptions in the applicant's cost analysis and, using the *OAQPS Control Cost Manual*, calculated a cost effectiveness for SCR to be approximately $3,961/ton of NO_x removed. The applicant also has expressed concerns regarding the storage and handling of aqueous ammonia.

Region 4 has evaluated the SCR cost assessments prepared by the applicant and the U.S. Fish and Wildlife Service. We have also given consideration to the concerns about the accidental release risks and potential environmental impacts of ammonia handling. Our conclusion following this review is that use of SCR combined with a DLN combustor should be considered BACT for NO_x emissions when the proposed facility is operated in combined cycle mode firing natural gas. The basis for our conclusion is as follows:

- For many recent combined cycle combustion turbine facilities, BACT for natural gas firing has been add-on control (SCR in almost all cases) with a DLN combustor.

- Nothing in our review of the GRU-Kelly Generating facility information (including the applicant's cost evaluation) leads us to conclude that the proposed facility is in some sense unique compared to other recent similar facilities such that use of SCR would be cost prohibitive for GRU-Kelly even though not cost prohibitive for other facilities.

- Use of SCR technology with combustion turbines is now widespread. While safety is certainly a concern with any process involving ammonia, the accumulated operating history of SCR systems should allow for the design and use of an SCR system at the GRU-Kelly Generating facility that is protective of the surrounding community. Further, careful operation and monitoring of the SCR system will help minimize any adverse environmental impacts from ammonia slip.

2. The proposed BACT for particulate matter (PM_{10}) is 10% opacity for visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT particulate matter emissions rate limit. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions should also list the corresponding emission rate for particulate matter (i.e., 9 lb/hr for natural gas, 17 lb/hr for fuel oil.)

3. The applicant has requested exemption from excess emissions due to startup, shutdown or malfunction for up to 4 hours in any 24-hour period. It is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

In conclusion, we request that the draft permit not be issued until EPA, FDEP, and the permit applicant reach consensus on the BACT determination for NO_x emissions.

Thank you for the opportunity to comment on the GRU-Kelly Generating Station's PSD permit application. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: NPS
NED
NED Branch
Alachua Co

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Environmental Consulting & Technology, Inc.

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November 10, 1999
ECT No. 990100-0200

SENT BY OVERNIGHT MAIL ON 11/11/99

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

Re: Florida Department of Environmental Protection (FDEP)
File Nos. 0010005-002-AC and PSD-FL-276
GRU—J.R. Kelly Power Plant—Repowering Project

Dear Mr. Linero:

On behalf of the City of Gainesville, Gainesville Regional Utilities (GRU), the following responses to comments provided by the U.S. Department of the Interior, Fish and Wildlife Service (USFWS) to the Department in correspondence dated October 6, 1999 are submitted for your review:

1. Because of the relatively small emissions increases, the potential for impacts to the air quality and air quality related values of the Class I areas is minimal.

Response

GRU concurs with this conclusion by the USFWS. Maximum modeled air quality impacts, assuming oil-firing operations, at the Okefenokee and Chassahowitzka National Wildlife Refuge Class I areas are projected to be well below the U.S. Environmental Protection Agency (EPA) significant impact levels for Class I areas. Maximum impacts will be even lower when natural gas, the primary fuel source, is utilized.

2. GRU's BACT analysis is incomplete because it improperly dismissed SCONO$_x$.

Response

As was discussed in Section 5.5.1 of the September 1999 permit application, SCONO$_x$™ technology is considered to be an emerging technology for large combustion turbines (CTs). The project cited by the USFWS, the La Paloma Power Generating Station located

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near Bakersfield, California, in an ozone nonattainment area, will consist of four, 250 megawatt (MW) power blocks. Three of these blocks will utilize conventional SCR control technology while the fourth will install $SCONO_x$™. The installation of $SCONO_x$™ technology on one of the four power blocks is essentially for the purpose of determining the commercial viability of this technology on large CTs.

$SCONO_x$™ technology, which is considerably more expensive than SCR control technology (from two to six times more expensive), is considered to represent the lowest achievable emission rate (LAER) applicable to nonattainment areas. LAER determinations do not consider economics. There are currently no CTs located in ozone attainment areas utilizing $SCONO_x$™ technology.

As was noted in the September 1999 permit application discussion of $SCONO_x$™ technology, this technology has little tolerance for sulfur compounds. Even natural gas, which contains very low levels of sulfur compounds (i.e., approximately 0.0006 weight percent), must be treated prior to combustion in a CT utilizing the $SCONO_x$™ technology. The GRU Repowering Project CT will employ distillate fuel oil containing no more than 0.05 weight percent sulfur as a back-up fuel source. Goal Line Environmental Technologies (GLET), the sole supplier of the proprietary $SCONO_x$™ technology, has declined to offer proposals for several CT projects which employ back-up fuel oil citing concerns with sulfur contamination of the $SCONO_x$™ catalyst.

As a municipal electric utility, GRU must be a source of reliable power generation. Accordingly, it is considered inappropriate for GRU to commit to the use of $SCONO_x$™ control technology for the repowering project CT when the commercial viability of this technology has not been demonstrated for a comparable size CT. Reliance on a single supplier of a control system also poses a commercial risk to GRU.

3. GRU's BACT analysis is deficient because it did not properly evaluate the economic and environmental feasibility of SCR.

Response

USFWS raised three issues regarding the economic analysis of SCR: (a) instrumentation costs, (b) interest rate, and (c) heat rate penalty. The SCR economic analysis has been reevaluated based on the USFWS comments and additional consideration of site-specific factors associated with the J.R. Kelly Power Plant Repowering Project. Detailed line item explanations of the revised SCR capital and annual cost estimates are provided in Tables 1 and 2, respectively. Comments on the revised SCR cost analysis are as follows:

1. The proposed combustion turbine/heat recovery steam generator (CT/HRSG) will be located at the J.R. Kelly Generating Station. The J.R. Kelly Generating Station

is an existing power generation facility located in downtown Gainesville, Florida. Because the CT/HRSG is a repowering project and will operate in conjunction with existing Unit No. 8 steam turbine, the new CT/HRSG unit must be situated in the vicinity of the Unit No. 8 steam turbine. Accordingly, constraints exist with respect to the availability of space and the location of the new CT/HRSG unit at the plant site. A plot plan of the J.R. Kelly Generating Station was provided in the September 1999 permit application package as Figure 2-2.

Due to location and space constraints, the addition of a SCR control system will require revisions to the project design and layout. The addition of a SCR control system (i.e., ammonia injection grid, ammonia/exhaust gas mixing zone, and SCR catalyst) will increase the length of the HRSG by approximately 15 feet (ft). This additional HRSG length will increase the *footprint* of the CT/HRSG unit such that revisions to the existing storm water management system located immediately south of the CT/HRSG unit will become necessary.

Due to these site-specific project considerations, the SCR cost analysis has been revised to include a capital cost for the HRSG modifications needed to accommodate the SCR control system ($185,000) and an estimated installation cost of $100,000 to address storm water management system revisions.

2. The USFWS comment regarding SCR instrumentation costs was that an allowance for instrumentation should not be included in the cost estimate. The vendor which provided the SCR quotation, Engelhard Corporation, indicates that only controls associated with the ammonia skid are included. Engelhard further indicated that their cost estimate includes control logic only and will require receiving a signal from a unit control system to be provided by others. The SCR vendor quote also does not include any instrumentation needed for the aqueous ammonia storage/vaporization system. Accordingly, an allowance for instrumentation costs is considered appropriate. Because a firm, definitive cost estimate is not required for a best available control technology (BACT) cost analysis, use of the EPA OAQPS factor of 0.10 times the purchased equipment cost is felt to be a reasonable approach and is consistent with the EPA OAQPS factor methodology employed for the other SCR control system capital costs.

3. SCR annual costs have been revised to include an allowance for catalyst disposal ($25,410), ammonia costs based on information received from a major supplier of ammonia, use of a 0.5 percent energy penalty as recommended by the USFWS and EPA, and a credit for annual emissions fees.

Regarding ammonia costs, Tanner Industries was contacted to obtain an estimate of the delivered cost of aqueous ammonia (nominal 28 weight percent ammonia [NH_3]) for the J.R. Kelly Generating Station. Tanner Industries, a major national supplier of ammonia, indicated that it is industry practice to quote the cost of aqueous ammonia costs on a dry (i.e., anhydrous) basis and delivery costs on a total weight (i.e., wet) basis. For the J.R. Kelly Generating Station Repowering Project, an estimate of $2,285 per shipment of delivered aqueous ammonia based on a 45,000 pound (22.5 ton) truck shipment was provided by Tanner Industries. Of this total, transportation costs were indicated to be $400 per shipment. These costs translate to a delivered aqueous ammonia cost of $102 per ton on a total weight (i.e., wet) basis. The ammonia cost on a dry, anhydrous basis excluding transportation is approximately $300 per ton assuming a 28 weight percent aqueous ammonia solution.

4. The USFWS comment concerning interest rate suggested a value of seven percent based on information contained in the EPA OAQPS Cost Control Manual. As described in the OAQPS Cost Control Manual, the applicable interest rate is the *pretax marginal rate of return* or *real private rate of return*. Accordingly, this interest rate is not a constant, fixed value but rather is project-specific and will vary depending on the profitability and cost of capital for the project being evaluated. The 8.75 percent interest rate used for the J.R. Kelly Generating Station Repowering Project represents a reasonable estimate of the cost of capital for GRU.

Comparisons between the revised GRU and USFWS SCR capital and annual cost estimates are provided in Tables 3 and 4, respectively. Comments regarding these comparisons are as follows:

1. The USFWS capital cost estimate excluded an allowance for an aqueous ammonia storage tank. When adjusted for this omission and the additional costs associated with the HRSG modifications and storm water management system revisions, the GRU and USFWS capital cost estimates are comparable; i.e., within 8 percent of each other.

2. The USFWS annual cost estimate includes apparent computational errors with respect to the calculation of annualized catalyst replacement cost, summation of direct costs, energy penalty cost, and indirect overhead cost. The USFWS annual cost estimate was corrected for these apparent mathematical errors as well as adjusting the estimate to include the capital recovery costs associated with the HRSG modifications and storm water management system revisions. Following these adjustments, the GRU and USFWS annual cost estimates are considered comparable; i.e., a difference of approximately 10 percent.

The revised SCR cost analysis is also considered to be conservative (i.e., under-estimate of actual cost effectiveness) for the following reasons:

1. Frequency of catalyst replacement was assumed to be 5 years in accordance with FDEP and USFWS recommendations. However, the SCR vendor emissions performance guarantee is only valid for 3 years of operation or 3.5 years after catalyst delivery, whichever occurs first. This vendor catalyst warranty is prorated over the guaranteed catalyst life. Use of a 3-year catalyst life will increase the estimated cost effectiveness to approximately $5,300 per ton of nitrogen oxides (NO_x) removed.

2. The calculation of SCR cost effectiveness was based on an assumed 100 percent capacity factor; i.e., 7,760 hours per year (hrs/yr) of gas-firing and 1,000 hrs/yr of oil-firing at baseload conditions. Lower actual utilization will result in a higher control cost on a $/ton of NO_x removed basis. For example, an overall 80 percent capacity actor (6,208 hrs/yr of gas-firing and 800 hrs/yr of oil-firing) yields a cost effectiveness of $5,725 per ton of NO_x removed.

3. Replacement of catalyst was assumed to occur during a scheduled maintenance CT/HRSG outage. If the catalyst replacement cannot be conducted concurrently with a scheduled maintenance outage, additional costs due to loss of power generation will be incurred. Assuming a 2 day unscheduled outage and a power cost of $0.03 per kilowatt per hour (kW/hr), the cost associated with the unscheduled outage is estimated to be approximately $191,500 excluding a credit for fuel not combusted during the outage.

4. Use of a 3 year catalyst life and overall 80 percent capacity factor will increase the cost effectiveness to $6,340 per ton of NO_x removed.

5. The proposed CT/HRSG unit is part of a repowering project planned for the J.R. Kelly Generating Station. Existing Unit 8 will cease operation following installation and operation of the new CT/HRSG unit. Actual NO_x emissions from Unit No. 8 during 1997 and 1998 averaged 94.1 tons per year (tpy). Accordingly, the *net* NO_x emission increase due to the repowering project is 113 tpy. Keeping the oil-firing project premises unchanged (i.e., 1,000 hrs/yr at 42 parts per million by volume dry [ppmvd] NO_x), the NO_x exhaust concentration from the J.R. Kelly Generating Station Repowering Project CT/HRSG unit during gas-firing is equivalent to a grass-roots GE 7EA CT/HRSG unit achieving <u>2.2 ppmvd</u> NO_x. This low level of NO_x emissions is well below the most stringent national BACT determination for CTs. The installation of a SCR control system to a CT/HRSG unit achieving such a low NO_x exhaust concentration would clearly be economically infeasible.

In summary, the installation and operation of a SCR control system for the J.R. Kelly Generating Station Repowering Project is considered to be economically unreasonable. Initial capital cost and installation expenses are estimated to be approximately

$2,000,000. Operation and maintenance of the SCR control system is estimated to cost over $600,000 annually. Cost effectiveness is estimated to range from $4,778 to $6,340 per ton of NO_x controlled. In addition, there are significant adverse environmental and energy impacts associated with the use of a SCR control system as discussed in the following sections.

Environmental Impacts

Installation of a SCR control system will result in emissions of ammonia due to the discharge of unreacted ammonia; i.e., ammonia slip. At a slip rate of 5 ppmvd, ammonia emissions are calculated to be 28.5 tpy at baseload and 59 degrees Fahrenheit (°F) ambient temperature. The 5 ppmvd ammonia slip rate is approximately equal to the NO_x concentration decrease (9—3.5 ppmvd or 5.5 ppmvd) resulting from the application of SCR control technology.

The excess ammonia is also available to react with sulfur trioxide (SO_3) in the exhaust stream to form ammonium sulfate ($[NH_4]_2SO_4$) fine particulate matter ($PM_{2.5}$). This reaction would approximately double PM/PM_{10} emissions during oil-firing; i.e., from 10 to 18 pounds per hour (lbs/hr). The additional $PM_{2.5}$ emissions will also result in an increase in ambient $PM_{2.5}$ levels as well as contribute to the formation of regional haze. Increases in ambient $PM_{2.5}$ levels are of concern because current ambient concentrations in many areas of Florida approach the National Ambient Air quality Standards (NAAQS) for this air contaminant.

As discussed above, the proposed CT/HRSG unit is part of a repowering project planned for the J.R. Kelly Generating Station. Existing Unit 8 will cease operation following installation and operation of the new CT/HRSG unit. Actual NO_x emissions from Unit No. 8 during 1997 and 1998 averaged 94.1 tpy. Accordingly, the repowering project will result in an actual NO_x emissions decrease of 94.1 tpy due to the cessation of operations of Unit 8.

With respect to accidental releases of aqueous ammonia, a 90 day supply of aqueous ammonia will require an approximate 16,000 gallon storage tank for the repowering project. Aqueous ammonia is designated an *extremely hazardous chemical* which is regulated extensively due to its toxicity. For example, the quantity of required aqueous ammonia storage, approximately 120,000 pounds, exceeds the applicability threshold of 20,000 pounds for ammonia solutions greater than 20 weight percent ammonia and therefore will be subject to the requirements of 40 Code of Federal Regulations (CFR) Part 68, Chemical Accident Prevention Provisions. These requirements include the preparation of a Risk Management Plan (RMP). The handling and storage of aqueous ammonia is also regulated under the Toxic Substance Control Act (TSCA), the Emergency Planning and Community Right-to-Know Act (EPCRA), by rules promulgated by the Occupational

Safety and Health Administration (OSHA), as well as other state and local regulatory programs.

Ammonia is very alkaline and reacts corrosively with all body tissues. A Material Safety Data Sheet (MSDS) for aqueous ammonia notes the following potential health effects:

Inhalation—Corrosive. Extremely destructive to tissues of the mucous membranes and upper respiratory tract. Symptoms may include burning sensation, coughing, wheezing, laryngitis, shortness of breath, headache, nausea, and vomiting. Inhalation may be fatal as a result of spasm inflammation and edema of the larynx and bronchi, chemical pneumonitis, and pulmonary edema.

Ingestion—Corrosive. Swallowing can cause severe burns of the mouth, throat, and stomach, leading to death. Can cause sore throat, vomiting, diarrhea.

Skin Contact—Dermal contact with alkaline corrosives may produce pain, redness, severe irritation, or full thickness burns. May be absorbed through the skin with possible systemic effects.

Eye Contact—Corrosive. Can cause blurred vision, redness, pain, severe tissue burns, and eye damage. Eye exposure may result in temporary or permanent blindness.

Chronic Exposure—Prolonged or repeated skin exposure may cause dermatitis. Prolonged or repeated exposure may cause eye, liver, kidney, or lung damage.

The MSDS also provides the following information concerning accidental release measures:

> Approach release from upwind. Ventilate area of leak or spill. Wear appropriate personal protective equipment as specified in Section 8. Isolate hazard area. Keep unnecessary and unprotected personnel from entering. Contain and recover liquid when possible. Carefully neutralize spill with dilute HCl. Collect liquid in an appropriate container or absorb with an inert material (e.g., vermiculite, dry sand, earth), and place in a chemical waste container. Use water spray to cool, absorb, and disperse vapors. Do not use combustible materials, such as saw dust. Do not flush to sewer! U.S. Regulations (Comprehensive Environmental Response, Compensation, and Liability Act [CERCLA]) require reporting spills and releases to soil, water, and air in excess of reportable quantities. The toll free number for the U.S. Coast Guard National Response Center is (800) 424-8802.

As discussed in the September 1999 permit application, the existing J.R. Kelly Generating Station is situated in the urbanized section of downtown Gainesville. Land use in the vicinity of the J.R. Kelly Generating Station is residential to the north and east, mixed residential/commercial to the west, and industrial to the south. Several redevelopment projects planned for the downtown Gainesville area will increase public use of this area. These projects include a new regional transportation center to the west and directly across the street from the repowering project, an EPA Brownfield Pilot Project that envisions the creation of a regional park on the large tract of land immediately south of the repowering project and the Union Street Station, a multi-story commercial/residential complex approximately three blocks northwest of the project site.

Due to the toxicity of aqueous ammonia and potential for accidental releases, it is considered inappropriate to transport, store, and handle this chemical in the Gainesville urban area, particularly in light of the minimal environmental benefits that would occur due to its use. Maximum annual NO_2 air quality impacts due to operation of the new CT/HRSG unit during oil-firing, <u>without a SCR control system</u>, are projected to be only 0.2 percent of the NAAQS for this air contaminant. During the predominant gas-firing mode of operation, maximum annual NO_2 air quality impacts, <u>without a SCR control system</u>, are projected to be only 0.01 percent of the NAAQS.

<u>Energy Impacts</u>

Energy impacts associated with the use of a SCR control system were discussed in Section 5.5.2 of the September 1999 permit application. In brief, the installation of SCR technology will cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH3 from storage to the injection nozzles and for NH_3 vaporization. At an energy penalty of 0.5 percent, lost power due to the increase in turbine back pressure will result in a $109,062 annual cost.

In summary, installation of a SCR control system is not considered to represent BACT for the J.R. Kelly Generating Station Repowering Project due to excessive costs, minimal environmental benefits, potential for accidental releases of aqueous ammonia in an urban area, and adverse energy impacts. An evaluation of NO_x BACT for the J.R. Kelly Generating Station Repowering Project should consider the following project-specific factors:

- The repowering project will cause a reduction of 94 tpy of NO_x emissions due to the cessation of operations of existing Unit No. 8. With the inclusion of this emissions decrease, the NO_x exhaust concentration from the J.R. Kelly Generating Station Repowering Project CT/HRSG unit during gas-firing is equivalent to a grass-roots GE 7EA CT/HRSG unit achieving <u>2.2 ppmvd</u> NO_x. The installation of a SCR control system to a CT/HRSG unit achieving such a low NO_x exhaust concentration would clearly be technically and economically infeasible.

- Location and space constraints exist at the existing J.R. Kelly Generating Station with respect to siting of the new CT/HRSG unit. The addition of a SCR control system will lengthen the HRSG unit such that revisions to an existing storm water management system will become necessary.

- Operation of a SCR control system will result in an ammonia slip exhaust concentration of 5 ppmvd. This concentration is approximately equal to the NO_x concentration reduction (i.e., 5.5 ppmvd) resulting from the application of SCR control technology. At baseload operations and 59°F, a 5 ppmvd ammonia slip concentration will result in ammonia emissions of approximately 30 tpy. The excess ammonia would also be available to react with SO_3 contained in the CT/HRSG exhaust stream; $PM_{2.5}$ emissions would increase, and PM/PM_{10} emissions during oil-firing would approximately double.

- Aqueous ammonia is a designated an *extremely hazardous chemical* which is regulated extensively due to its toxicity. The regulation of aqueous ammonia under 40 CFR Part 68 Chemical Accident Prevention Provisions demonstrates that transportation, handling, and storage of aqueous ammonia are activities that, in the judgement of the EPA, may potentially result in the accidental release of a toxic chemical. The potential for accidental releases of aqueous ammonia in an urban setting with significant public exposure poses an unnecessary public health risk, particularly in light of the minimal environmental benefits that may occur due to its use for the J.R. Kelly Generating Station Repowering Project.

- Maximum annual NO_2 air quality impacts due to operation of the new CT/HRSG unit during oil-firing, without a SCR control system, are projected to be only 0.2 percent of the NAAQS for this air contaminant. During the predominant gas-firing mode of operation, maximum annual NO_2 air quality impacts, without a SCR control system, are projected to be only 0.01 percent of the NAAQS. These already low air quality impacts show that the addition of a SCR control system will provide no discernable improvement in NO_2 ambient air quality.

- The application of CT dry low-NO_x (DLN) control technology represents pollution prevention in that the technology prevents the creation of an air contaminant by means of process combustion modifications. Pollution prevention technology achieving comparable emission reductions is considered environmentally superior to add-on controls because lower quantities of solid wastes, wastewater, and collateral air emissions are generated compared to add-on controls. The regulatory definition of BACT specifically includes *innovative combustion techniques* as a control technology which can be considered in a BACT analysis. DLN technology would clearly qualify as an innovative combustion technique. The history of DLN development leads to the conclusion that future improvements in performance (i.e., lower NO_x emissions) are likely to occur. Due to the significant economic costs and collateral air emissions associated with add-on control systems such as SCR, further encouragement by the regulatory agencies of improved DLN performance is considered desirable. Mandating SCR control systems for CTs that achieve single digit NO_x exhaust concentrations would likely do the opposite by reducing the incentive to further refine and improve DLN technology. Regulatory encouragement of further improvement in DLN technology would also prove environmentally beneficial with respect to reducing NO_x emissions from simple-cycle CTs since these units generally do not have the option of using SCR control technology due to temperature and economic considerations.

If you have any questions, please feel free to give me a call at 352/332-0444.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

TWD/edd

Attachment

cc: EPA
NPS
NED
NED Branch
Alachua Co.

Table 1-1, Summary of Air Pollutant Standards and Terms

City of Gainesville, GRU
J. R. Kelly Generating Station

Permit Revision No.: 0010005-003-AV
Facility ID No.: 0010005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
-006	Fossil Fuel Fired Steam Generator Unit No. 6

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuels	Hours/Year	Standards	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citations	See permit conditions
VE	Nat. Gas	8760	20% opacity					62-296.406(1), F.A.C.	III.A.4.
VE(SB)**	Nat. gas	1095	60% opacity					62-210.700(3), F.A.C.	III.A.5.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** SB refers to "soot blowing" and "load change".

Table 1-1, Summary of Air Pollutant Standards and Terms

City of Gainesville, GRU
J. R. Kelly Generating Station

Permit Revision No.: 0010005-003-AV
Facility ID No.: 0010005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
-007	Fossil Fuel Fired Steam Generator Unit No. 7

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuels	Hours/Year	Standards	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citations	See permit conditions
VE	Nat. Gas or Nos. 4, 5, 6 F.O.	8760	20% opacity ***					62-296.405(1)(a), F.A.C.	III.B.4.
VE(SB)**		1095	60% opacity					62-210.700(3), F.A.C.	III.B.5.
PM	Nos. 4, 5, 6 F.O.	8760	0.1 lb/MMBtu			24.9	109.1	62-296.405(1)(b), F.A.C.	III.B.6.
PM(SB)**	Nos. 4, 5, 6 F.O.	1095	0.3 lb/MMBtu			74.7	40.89	62-210.700(3), F.A.C.	III.B.7.
SO2	Nos. 4, 5, 6 F.O.	8760	2.75 lb/MMBtu			684.75	2,999.20	62-296.405(1)(c)j., F.A.C.	III.B.8.
SO2	Nos. 4, 5, 6 F.O.	8760	2.50% sulfur content by weight on liquid fuels						III.B.9.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** SB refers to "soot blowing" and "load change".
*** Except for one two-minute period per hour up to 40%

Table 2-1, Summary of Compliance Requirements

City of Gainesville, GRU
J. R. Kelly Generating Station

Permit Revision No.: 0010005-003-AV
Facility ID No.: 0010005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
-006	Fossil Fuel Fired Steam Generator Unit No. 6

Pollutant Name or Parameter	Fuel	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit conditions
VE	Nat. gas	DEP Method 9	before permit renewal	01-Mar	1 hour	no	III.A.8., A.10.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Table 2-1, Summary of Compliance Requirements

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
-007	Fossil Fuel Fired Steam Generator Unit No. 7

Pollutant Name or Parameter	Fuels	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit conditions
VE	Nos. 4, 5, 6 F.O. or nat. gas	DEP Method 9	annually		1 hour		III.B.11., B.20.
PM	Nos. 4, 5, 6 F.O.	EPA Methods 17, 5, 5B or 5F	annually		1 hour	no	III.B.12., B21.
SO2	Nos. 4, 5, 6 F.O.	EPA Methods 6, 6A, 6B, or 6C or	annually		1 hour		III.B.13.
		ASTM D 2622-92 D4294-90, D1552-90, D4177-82 or both ASTM D4057-88 and D129-91	each fuel delivery		N/A		III.B.15.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Table 1. GRU J.R. Kelly Plant Repowering Project - Basis for SCR Capital Costs

Item	($)	OAQPS Factor	Basis
A. Direct Costs			
Purchased Equipment	945,000	A	Engelhard quote of $710,000 + cost of NH_3 storage tank + HRSG Modifications. SCR Cost = $710,000 NH_3 storage tank = $50,000 (engineering estimate) HRSG Modifications = $185,000 (HRSG vendor estimate) Total SCR System = $710,000 + $50,000 + $185,000 = $945,000
Instrumentation	94,500	0.10 x A	Purchased Equipment x OAQPS Instrumentation Factor of 0.10 Instrumentation = $945,000 x (0.10) = $94,500
Sales Tax	56,700	0.06 x A	Purchased Equipment x 6% sales tax Sales Tax = $945,000 x (0.06) = $56,700
Freight	47,250	0.05 x A	Purchased Equipment x OAQPS Freight Factor of 0.05 Freight = $945,000 x (0.05) = $47,250
Subtotal Purchased Equipment	1,143,450	B	Sum of Purchased Equipment + Instrumentation + Sales Tax + Freight Subtotal Purchased Equipment = $945,000 + $94,500 + 56,700 + $47,250 Subtotal Purchased Equipment = $1,143,450
Subtotal Installation Cost	443,035	0.30 x B	Subtotal Purchased Equipment x OAQPS Installation Cost Factor of 0.30 + Stormwater Management Revisions OAQPS Installation Cost Factor = (0.08 + 0.14 + 0.04 + 0.02 + 0.01 + 0.01) = 0.30 Subtotal Installation Cost = $1,143,450 x 0.03 = $343,035 Stormwater Management Revisions = $100,000 Total Installation Cost = $343,035 + $100,000 = $443,035
Subtotal Direct Costs	1,586,485		Subtotal Purchased Equipment + Subtotal Installation Cost Subtotal Direct Costs = $1,143,450 + $443,035 = $1,586,485
B. Indirect Costs			
Subtotal Indirect Costs	354,470	0.31 x B	Subtotal Purchased Equipment x OAQPS Indirect Cost Factor of 0.31 OAQPS Indirect Cost Factor = (0.10 + 0.05 + 0.10 + 0.02 + 0.01 + 0.03) = 0.31 Subtotal Indirect Costs = $1,143,450 x 0.31 = $354,470
Total Capital Investment	**1,940,955**		Subtotal Direct Cost + Subtotal Indirect Cost Total Capital Investment = $1,586,485 + $354,470 = $1,940,955

Source: ECT, 1999.

Table 2. GRU J.R. Kelly Repowering Project - Basis for SCR Annual Operating Costs (Page 1 of 4)

Item	($)	OAQPS Factor	Basis
A. Direct Costs			
Operator Labor	15,549	A	0.5 hrs/shift x 3 shifts/day x 365 dys/yr x $28.40/hr Operator Labor = (0.5) x (3) x (365) x (28.40) = $15,549
Supervisor Labor	2,332	0.15 x A	Operator Labor x OAQPS Supervisor Labor Factor of 0.15 Supervisor Labor = $15,549 x 0.15 = $2,332
Maintenance Labor	16,759	B	0.5 hrs/shift x 3 shifts/day x 365 dys/yr x $30.61/hr Maintenance Labor = (0.5) x (3) x (365) x (30.61) = $16,759
Maintenance Material	16,759	1.0 x B	Maintenance Labor x OAQPS Supervisor Labor Factor of 1.0 Maintenance Materials = $16,759 x 1.0 = $16,759
Subtotal Labor and Materials	51,399	C	Operator Labor + Supervisor Labor + Maintenance Labor + Maintenance Materials Subtotal Labor and Materials = $15,549 + $2,332 + $16,759 + $16,759 = $51,399
Catalyst Replacement Costs	453,910		Engelhard quote of $350,000 + sales tax + freight + replacement labor + disposal costs Catalyst Cost = $350,000 Sales Tax = $350,000 x 0.06 = $21,000 Freight = $350,000 x 0.05 = $17,500 Replacement labor = $40,000 Disposal Costs = $500/ton = (50.8 ton) x ($500/ton) = $25,410 Catalyst Replacement Cost = $350,000 + $21,000 + $17,500 + $40,000 + $25,410 Catalyst Replacement Cost = $453,910
Annualized Catalyst Replacement Costs	115,941		Total Catalyst Replacement Cost x Capital Recovery Factor (CRF) CRF = $[i \times (1 + i)^n] / [(1+i)^n - 1]$ i = annual pretax marginal rate of return on private investment = 8.75% (0.0875) for GRU n = frequency of catalyst replacement = 5 years CRF = $[0.0875 \times (1+0.0875)^5] / [(1+0.0875)^5 - 1]$ = 0.25543 Annualized Catalyst Replacement Cost = $453,910 x 0.25543 = $115,941

Table 2. GRU J.R. Kelly Repowering Project - Basis for SCR Annual Operating Costs (Page 2 of 4)

Item	($)	OAQPS Factor	Basis
Electricity Cost	9,497		Power for NH_3 Pump and Dilution Air Blower + Power to Vaporize Aqueous NH_3 Power for NH_3 Pump and Air Blower = 5 kW x \$0.030 kWh x 8,760 hrs/yr = \$1,314 Power to Vaporize Aqueous NH_3 = 2 kW per lb NH_3 (anhydrous) = [(2 kW) x (0.28 lb NH_3 / lb $NH_{3\text{-}aq.}$) x (55.6 lb $NH_{3\text{-}aq.}$/hr)] x \$0.030 kWh x 8,760 hrs/yr = \$8,183 Electricity Cost = \$1,314 + \$8,183 = \$9,497
Aqueous Ammonia Cost	24,830		Aqueous NH_3 = \$102/ton; 28 weight % NH_3 solution; 1:1 molar ratio of NH_3 to NO_x NO_x = 90% NO + 10% NO_2, by volume; SCR Control Efficiency = 61.1 % Molecular Weight (MW) NO = 30 lb/mole; MW NO_2 = 46 lb/mole MW NO_x = (.9 x 30) + (.1 x 46) = 31.6 lb NO_x / mole NO_x NO_x Controlled (gas) = (32.0 lb/hr) x (61.1/100) = 19.6 lb/hr NO_x Controlled (oil) = (166.0 lb/hr) x (61.1/100) = 101.4 lb/hr Aqueous NH_3 Usage (gas) = (NO_x lb/hr) x (1 mole NH_3 / 1 mole NO_x) x (17 lb NH_3 / mole NH_3) x (mole NO_x / 31.6 lb NO_x) x (100 lb $NH_{3\text{-}aq.}$ / 28 lb NH_3) x (7,760 hrs/yr) x (1 ton/2,000 lb) = (19.6) x (1/1) x (17) x (1/31.6) x (100/28) x (7,760) x (1/2,000) = 146.0 ton/yr Aqueous NH_3 Usage (oil) = (NO_x lb/hr) x (1 mole NH_3 / 1 mole NO_x) x (17 lb NH_3 / mole NH_3) x (mole NO_x / 31.6 lb NO_x) x (100 lb $NH_{3\text{-}aq.}$ / 28 lb NH_3) x (1,000 hrs/yr) x (1 ton/2,000 lb) = (101.4) x (1/1) x (17) x (1/31.6) x (100/28) x (1,000) x (1/2,000) = 97.4 ton/yr Total Aqueous NH_3 Usage = Aqueous NH_3 Usage (gas) + Aqueous NH_3 Usage (oil) Total Aqueous NH_3 Usage = 146.0 ton/yr + 97.4 ton/yr = 243.4 ton/yr Aqueous NH_3 Cost = 243.4 ton/yr x \$102/ton = \$24,830
Subtotal Raw Materials and Utilities	34,327		Electricity Cost + Aqueous Ammonia Cost Subtotal Raw Materials and Utilities = \$9,497 + \$24,830 = \$34,327

Table 2. GRU J.R. Kelly Repowering Project - Basis for SCR Annual Operating Costs (Page 3 of 4)

Item	($)	OAQPS Factor	Basis
Energy Penalties			
Turbine Backpressure	109,062		Turbine Backpressure Penalty = 0.5% (EPA, 1993.) CT Power Output = 83,000 kW Power Cost = $0.030 kW; Annual Hours = 8,760 hrs/yr Turbine Backpressure Penalty = (0.5/100) x (83,000 kW) x (8,760 hrs/yr) x ($0.030/kWh) Turbine Backpressure Penalty = $109,062
Subtotal Direct Costs	310,729		Subtotal Direct Costs = Subtotal Labor and Materials + Annualized Catalyst Replacement Cost + Subtotal Raw Materials and Utilities + Turbine Backpressure Subtotal Direct Costs = $51,399 + $115,941 + $34,327 + $109,062 Subtotal Direct Costs = $310,729
B. Indirect Costs			
Overhead	30,840	0.60 x C	Subtotal Labor and Materials x OAQPS Overhead Cost Factor Overhead = $51,399 x 0.60 = $30,840
Administrative Charges	38,819	0.02 x TCI	Total Capital Investment x OAQPS Administrative Charges Factor Administrative Charges = $1,940,955 x 0.02 = $38,819
Property Taxes	19,410	0.01 x TCI	Total Capital Investment x OAQPS Property Tax Factor Property Taxes = $1,940,955 x 0.01 = $19,410
Insurance	19,410	0.01 x TCI	Total Capital Investment x OAQPS Insurance Factor Insurance = $1,940,955 x 0.01 = $19,410

Table 2. GRU J.R. Kelly Repowering Project - Basis for SCR Annual Operating Costs (Page 4 of 4)

Item	($)	OAQPS Factor	Basis
Capital Recovery	189,762		Capital Recovery = (TCI - Initial Catalyst Cost) x CRF TCI = \$1,940,955; Initial Catalyst Cost = \$388,500 $CRF = [i \times (1 + i)^n] / [(1+i)^n - 1]$ i = annual pretax marginal rate of return on pivate investment = 8.75% (0.0875) for GRU n = control system life = 15 years $CRF = [0.0875 \times (1+0.0875)^{15}] / [(1+0.0875)^{15} - 1] = 0.12223$ Capital Recovery = (\$1,940,955 - \$388,500) x 0.12223 = \$189,762
Subtotal Indirect Costs	298,241		Subtotal Indirect Costs = Overhead + Administrative Charges + Property Taxes + Insurance + Capital Recovery Subtotal Indirect Costs = \$30,840 + \$38,819 + \$19,410 + \$19,410 + \$189,762 Subtotal Direct Costs = \$298,241
Total Annual Cost	608,970		Total Annual Cost = Subtotal Direct Costs + Subtotal Indirect Costs Total Annual Cost = \$310,729 + \$298,241 Total Annual Cost = \$608,970
Emissions Fee Credit	3,170		NO_x controlled = 126.8 ton/yr FDEP Annual Emissions Fee Rate = \$25.00 per ton Emissions Fee Credit = (126.8 ton/yr) * (\$25.00/ton) = \$3,170
Cost Effectivness	**4,778**		Cost Effectiveness = (Total Annual Cost - Emissions Fee Credit) / tons NO_x Controlled Tons NO_x Controlled (gas) = 32.0 lb/hr x (61.1/100) x 7,760 hrs/yr x (1 ton/2,000 lb) Tons NOx Controlled (oil) = 166.0 lb/hr x (61.1/100) x 1,000 hrs/yr x (1 ton/2,000 lb) Tons NO_x Controlled = 76.0 tpy + 50.8 tpy = 126.8 tpy Total Annual Cost - Emissions Fee Credit = \$608,970 - \$3,170 = \$605,800 Cost Effectiveness = \$605,800 / 126.8 tons = \$4,778

Table 3. GRU J.R. Kelly Plant Repowering Project
Evaluation of Fish & Wildlife Service (F&WS) BACT NO_x Economic Analysis
Comparison of SCR Capital Costs

Cost Item	Costs ($)					Comment
	F&WS	F&WS (adjusted)[1]	GRU	% Difference[2]	% Difference[3]	
Direct Costs						
Purchased Equipment Costs (PEC)						
SCR	710,000	710,000	710,000	0.0	0.0	
Ammonia Storage	0	50,000	50,000	100.0	0.0	Not included in F&WS estimate
HRSG Modifications	0	185,000	185,000	100.0	0.0	Not included in F&WS estimate
Total (A)	710,000	945,000	945,000	24.9	0.0	
Instrumentation	0	0	94,500	100.0	100.0	Not included in F&WS estimate
Sales Tax	42,600	56,700	56,700	24.9	0.0	
Freight	35,500	47,250	47,250	24.9	0.0	
Purchased Equipment Costs (B)	788,100	1,048,950	1,143,450	31.1	8.3	
Installation Costs	236,430	314,685	343,035	31.1	8.3	
Site Preparation	0	0	0	0.0	0.0	
Buildings	0	0	0	0.0	0.0	
Stormwater Management Revisions	0	100,000	100,000	100.0	0.0	Not included in F&WS estimate
Total Installation Costs	236,430	414,685	443,035	46.6	6.4	
Total Direct Costs (DC)	1,024,530	1,463,635	1,586,485	35.4	7.7	
Indirect Costs (IC)	244,311	325,175	354,470	31.1	8.3	
Total Capital Investment (DC + IC)	1,268,841	1,788,810	1,940,955	34.6	7.8	Adjusted difference is within ±30% OAQPS "study" cost estimate accuracy.

[1] Adjusted to include NH_3 storage tank, HRSG modifications, and stormwater management revisions.
[2] [(GRU - F&WS) / GRU] x 100
[3] [(GRU - F&WS(adjusted)) / GRU] x 100

Sources: Engelhard, 1999.
ECT, 1999.
F&WS, 1999.
GRU, 1999.

Table 4. GRU J.R. Kelly Plant Repowering Project
Evaluation of Fish & Wildlife Service (F&WS) BACT NO_x Economic Analysis
SCR Annual Operating Costs

Item	F&WS	F&WS (adjusted)[1]	GRU	% Difference[2]	% Difference[3]	Comment
Direct Annual Costs (DC)						
Operating Labor						
Operator	15,549	15,549	15,549	0.0	0.0	
Supervisor	2,332	2,332	2,332	0.0	0.0	
Maintenance						
Labor	16,759	16,759	16,759	0.0	0.0	
Materials	16,759	16,759	16,759	0.0	0.0	
Operating Materials						
Reagent (NH_3)	27,324	27,324	24,830	-10.0	-10.0	
Electricity	772	772	9,497	91.9	91.9	F&WS estimate based on vaporization of anhydrous NH_3, excludes dilution air blowers
Catalyst Replacement	350,000	350,000	428,500	18.3	18.3	F&WS estimate excludes sales tax, freight, and installation labor costs
Catalyst Disposal	25,000	25,000	25,410	1.6	1.6	
Catalyst Replacement (annualized)	70,000	91,459	115,941	39.6	21.1	F&WS estimate based on 7% interest, GRU estimate based on project interest rate of 8.75% Apparent error in F&WS calculation of annualized cost; CRF = 0.24389 @ 5yrs and 7.0 %
Total Direct Costs (DC)	148,723	170,954	201,667	26.3	15.2	Apparent error in F&WS summation of direct capital costs; total = $149,495
Energy Costs						
Heat Rate Penalty (Turbine Backpressure)	122,640	140,160	109,062	-12.4	-28.5	F&WS estimate based on 0.5% power penalty, $0.04/kW, and 80 MW Apparent error in F&WS calculation of energy penalty GRU estimate based on 0.5% power penalty, $0.03/kW, and 83 MW
Indirect Annual Costs (IC)						
Overhead	47,234	30,840	30,840	-53.2	0.0	Apparent error in F&WS calculation of overhead cost
Administrative Charges	25,377	25,377	38,819	34.6	34.6	
Property Tax	12,688	12,688	19,410	34.6	34.6	
Insurance	12,688	12,688	19,410	34.6	34.6	
Capital Recovery	130,781	153,746	189,762	31.1	19.0	F&WS estimate based on 7.0% interest rate, 15 yr equipment life GRU estimate based on 8.75% interest rate, 15 yr equipment life
Total IC	228,768	235,340	298,241	23.3	21.1	
Total Annual Cost (DC + IC + Energy Penalty)	500,131	546,454	608,970	17.9	10.3	

Table 4. GRU J.R. Kelly Plant Repowering Project
Evaluation of Fish & Wildlife Service (F&WS) BACT NO_x Economic Analysis
SCR Annual Operating Costs (Page 2 of 2)

Item	F&WS	F&WS (adjusted)[1]	GRU	% Difference[2]	% Difference[3]	Comment
Cost Effectiveness						
Uncontrolled NO_x Emissions (ton/yr)	207.0	207.0	207.5	0.2	0.2	
Controlled NO_x Emissions (ton/yr)	126.0	126.0	126.8	0.6	0.6	
Annual Cost	500,131	546,454	608,970	17.9	10.3	
Annual Cost - Emission Fees	(3,780)	(3,780)	(3,170)	-19.2	-19.2	F&WS estimate based on $30/ton, GRU estimate based on $25/ton
Cost/ton	3,961	4,307	4,778	17.1	9.9	

[1] Adjusted to include NH_3 storage tank, HRSG modifications, and stormwater management revisions.
[2] [(GRU - F&WS) / GRU] x 100
[3] [(GRU - F&WS(adjusted)) / GRU] x 100

Sources: Engelhard, 1999.
ECT, 1999.
F&WS, 1999.
GRU, 1999.

ECT
Environmental Consulting & Technology, Inc.

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OCT 26 1999
BUREAU OF AIR REGULATION

October 25, 1999
ECT No. 990100-0200-0100

SENT BY OVERNIGHT MAIL ON 10/25/99

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

**Re: Florida Department of Environmental Protection (FDEP)
File Nos. 0010005-002-AC and PSD-FL-276
GRU – J.R. Kelly Power Plant – Repowering Project**

Dear Mr. Linero:

On behalf of the City of Gainesville, Gainesville Regional Utilities (GRU), seven copies of a Supplemental Best Available Control Technology Analysis for Simple Cycle Operation are enclosed in response to your correspondence to GRU dated October 6, 1999. Responses to the comments provided by the U.S. Department of the Interior, Fish and Wildlife Service in correspondence to the Department dated October 6, 1999 are being prepared and will be provided to you shortly.

Your continued expeditious processing of the GRU J.R. Kelly Power Plant Repowering Project will be appreciated. Please contact Yolanta Jonynas of GRU at 352/334-3400, Ext. 1284 or the undersigned at 352/332-6230, Ext.351, if there are any further questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Enclosures

cc: Ms. Yolanta Jonynas, GRU

cc: EPA
NPS
NED
NED Branch
Alachua Co.

3701 Northwest 98TH Street
Gainesville, FL 32606
(352) 332-0444
FAX (352) 332-6722

5A.0 SUPPLEMENTAL BACT ANALYSIS FOR SIMPLE-CYCLE OPERATION

In response to FDEP's correspondence dated October 6, 1999 (attached), a BACT analysis to address simple-cycle mode operation has been prepared to supplement the original BACT analysis submitted as Section 5.0 of the Application for Air Construction Permit package dated September 1999. Those portions of the original BACT analysis that remain unchanged are addressed by reference to the original application.

Because the CTG HRSG will be unfired (does not include the capability for supplemental duct burner firing), CTG emissions will be the same for both simple- and combined-cycle modes of operation. The primary difference between the two modes of operation is the CTG exhaust gas stack temperature; approximately 1,050°F for simple-cycle mode versus 385°F for combined-cycle mode.

5A.1 METHODOLOGY

The BACT analyses for simple-cycle mode operation were performed using the same EPA procedures and cost factors as previously described in Section 5.1 of the September 1999 application.

As indicated in Section 3.3, Table 3-2 of the September 1999 permit application, net annual emission rate increases of NO_x, CO, and PM_{10} for the repowering project exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses for simple-cycle operation using the five-step top-down BACT method are provided in Sections 5A.3, 5A.4, and 5A.5 for combustion products (PM_{10}), products of incomplete combustion (CO), and acid gases (NO_x), respectively.

5A.2 FEDERAL AND FLORIDA EMISSION STANDARDS

The federal and Florida emission standards previously described in Section 5.2 of the September 1999 permit application are applicable for both simple- and combined-cycle modes of operation.

5A.3 BACT ANALYSIS FOR PM_{10}

The BACT analysis for PM_{10} emissions previously provided in the September 1999 permit application is applicable to both simple- and combined-cycle modes of operation. Accordingly, the conclusions regarding BACT for PM/PM_{10} provided in the September 1999 permit application are also valid for simple-cycle mode operation. Specifically, the minor PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM_{10} concentrations. The estimated PM_{10} exhaust concentration for the repowering project CTG during oil-firing at base load and 59°F during simple-cycle mode operation is approximately 0.002 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

5A.3.1 PROPOSED BACT EMISSION LIMITATIONS

Because postprocess stack controls for PM_{10} are not appropriate for CTGs, the use of good combustion practices and clean fuels is considered to be BACT for both simple- and combined-cycle modes of operation. The repowering project CTG will use the latest, advanced combustor technology to maximize combustion efficiency and minimize PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTG will be fired primarily with pipeline quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up fuel source. Due to the difficulties associated with stack testing exhaust streams containing low PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTGs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM_{10} for both simple- and combined-cycle modes of operation. Table 5A-1summarizes the PM_{10} BACT emission limit proposed for the repowering project CTG.

5A.4 BACT ANALYSIS FOR CO

The discussion of CO formation, potential control technologies, and energy and environmental impacts previously provided in the September 1999 permit application are applicable to both simple- and combined-cycle modes of operation.

Table 5A-1. Proposed PM_{10} BACT Emission Limit—Simple- and Combined-Cycle Modes

Emission Source	Proposed PM_{10} BACT Emission Limit* (% Opacity)
GE PG7121 (7EA), CC-1	10

*Maximum opacity for all operating scenarios.

Source: ECT, 1999.

5A.4.1 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors and repowering project-specific economic factors previously summarized in Tables 5-1 and 5-9 of the September 1999 permit application. Tables 5A-2 and 5A-3 summarize specific capital and annual operating costs for the simple-cycle mode operation oxidation catalyst control system. Capital costs shown in Table 5A-2 are based on a vendor quote (Engelhard Corporation) for a similar GE 7EA simple-cycle CTG project. The costs shown in Tables 5A-2 and 5A-3 are considered to be conservative (i.e., to underestimate actual costs) because they do not include the costs associated with ductwork modifications to allow for installation of the CO oxidation catalyst system prior to the HRSG bypass stack.

Following the first year of operation, base case CTG exhaust CO concentrations for both natural gas and fuel oil firing are 20 ppmvd, respectively. Control efficiency for the CO oxidation catalyst system, consistent with efficiencies typically required for oxidation catalyst systems located in nonattainment areas, is assumed to be 90 percent. Base case and controlled CO emission rates are summarized in Table 5A-4.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $2,210 per ton of CO removed during simple-cycle mode operation. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered economically feasible. Table 5A-4 summarizes results of the oxidation catalyst economic analysis for simple-cycle mode operation.

5A.4.2 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from CTGs is typically required only for facilities located in CO nonattainment areas. The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs fired with natural gas and distillate fuel oil. Because CO emission rates from CTGs are inherently low, further reductions

Table 5A-2. Capital Costs for Oxidation Catalyst System—Simple-Cycle Mode

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	766,000	A
Sales tax	45,960	$0.06 \times A$
Instrumentation	76,600	$0.10 \times A$
Freight	38,300	$0.05 \times A$
Subtotal Purchased Equipment	**$926,860**	**B**
Installation		
Foundations and supports	74,149	$0.08 \times B$
Handling and erection	129,760	$0.14 \times B$
Electrical	37,074	$0.04 \times B$
Piping	18,537	$0.02 \times B$
Insulation for ductwork	9,269	$0.01 \times B$
Painting	9,269	$0.01 \times B$
Subtotal Installation Cost	**$278,058**	
Subtotal Direct Costs	**$1,204,918**	
Indirect Costs		
Engineering	92,686	$0.10 \times B$
Construction and field expenses	46,343	$0.05 \times B$
Contractor fees	92,686	$0.10 \times B$
Start-up	18,537	$0.02 \times B$
Performance test	9,269	$0.01 \times B$
Contingency	27,806	$0.03 \times B$
Subtotal Indirect Costs	**$287,327**	
TOTAL CAPITAL INVESTMENT	**$1,492,245**(TCI)	

Sources: Engelhard, 1999.
ECT, 1999.

Table 5A-3. Annual Operating Costs for Oxidation Catalyst System—Simple-Cycle Mode

Item	Dollars	OAQPS Factor or Basis
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	640,340	Vendor quote + labor + freight + sales tax
Credit for used catalyst	(86,400)	15% of replacement catalyst
Subtotal Catalyst Costs	**$553,940**	
Annualized Catalyst Costs	**$141,491**	8.75% @ 5 yrs
Energy penalties		
Turbine backpressure	43,625	0.2% penalty
Subtotal Direct Costs	**$185,116**	(TDC)
Indirect Costs		
Administrative charges	29,845	0.02 × TCI
Property taxes	14,922	0.01 × TCI
Insurance	14,922	0.01 × TCI
Capital recovery	131,287	8.75% @ 10 yrs
Subtotal Indirect Costs	**$190,977**	
TOTAL ANNUAL COST	**$376,092**	

Sources: Engelhard, 1999.
GRU, 1999.
ECT, 1999.

Table 5A-4. Summary of CO BACT Analysis—Simple-Cycle Mode

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
Oxidation catalyst	4.3	18.9	170.2	1,492,245	376,092	2,210	4,962	Y	Y
Baseline	43.2	189.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,760 hr/yr gas-firing and 1,000 hr/yr oil-firing, 20 ppmvd CO gas and oil firing.

Sources: GE, 1999.
Engelhard, 1999.
GRU, 1999.
ECT, 1999.

through the use of oxidation catalysts will result in only minor improvement in air quality (i.e., well below the defined PSD significant impact levels for CO).

The application of DLN combustors for the GE 7EA CTG results in a trade-off between NO_x and CO emission rates (i.e., controlling NO_x exhaust concentrations to 9 ppmvd at 15 percent O_2 causes an increase in CO emissions compared to a standard combustor). Because ambient CO concentrations in the vicinity of the J.R. Kelly Generating Station would be expected to be well below ambient standards, the reduction in NO_x emissions is considered to have a greater environmental benefit and would more than compensate for the higher CO emission rates associated with DLN technology.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO for simple-cycle mode operation. Following the first year of operation, at baseload operation for both natural gas and distillate fuel oil firing, maximum CO exhaust concentration and hourly mass emission rate from the CTG will be 20 ppmvd and 43.0 lb/hr (at ISO conditions) for both simple- and combined-cycle modes of operation. These CO exhaust concentrations and emission rates are consistent with recent FDEP BACT determinations for CTGs (e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5). Table 5A-5 summarizes the CO BACT emission limits proposed for the repowering project for both simple- and combined-cycle modes of operation.

5A.5 BACT ANALYSIS FOR NO_X

The discussion of NO_x formation, potential control technologies, technical feasibility, and energy and environmental impacts provided in the September 1999 permit application address both simple- and combined-cycle modes of operation. For simple-cycle mode operation, technically feasible NO_x control technologies consist of advanced DLN combustors (natural gas firing), water injection (distillate fuel oil firing), and the application of postcombustion high temperature SCR control technologies.

Table 5A-5. Proposed CO BACT Emission Limits—Simple- and Combined-Cycle Modes

Emission Source	Proposed CO BACT Emission Limits lb/hr*	ppmvd
GE PG7121 (7EA) CTG† (Natural Gas-Fired)	54	25
GE PG7121 (7EA) CTG† (Natural Gas-Fired)	43	20
GE PG7121 (7EA) CTG (Distillate Fuel Oil-Fired)	43	20

*At ISO conditions.
†First year operation.

Sources: GE, 1999.
ECT, 1999.

5A.5.1 ECONOMIC IMPACTS

An assessment of economic impacts for simple-cycle operations was performed by comparing control costs between a baseline case of advanced DLN combustor technology and baseline technology with the addition of high temperature ("hot") SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 9.0 and 42 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing, respectively. SCR technology was premised to achieve NO_x concentrations of 3.5 and 16.3 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing, respectively. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired CTGs equipped with DLN combustor technology and SCR controls. As supplied by GE, the PG7121 (7EA) unit is equipped with dual-fuel low-NO_x combustors (i.e., DLN during natural gas firing and water injection during distillate fuel oil firing). GE offers no other option with respect to combustor type or design.

The cost impact analysis was conducted using the OAQPS factors and repowering project specific economic factors previously summarized in Tables 5-1 and Table 5-9 of the September 1999 application. Emission reductions were calculated assuming baseload operation for 7,760 and 1,000 hr/yr (for natural gas and distillate fuel oil firing, respectively) at an annual average ambient temperature of 59°F. Tables 5A-6 and 5A-7 summarize specific capital and annual operating costs for the simple-cycle, high-temperature SCR control system, respectively. Capital costs shown in Table 5A-7 are based on a vendor quote (Engelhard Corporation) for a similar GE 7EA simple-cycle CTG project. The costs shown in Tables 5A-6 and 5A-7 are considered to be conservative (i.e., to underestimate actual costs) because they do not include the costs associated with ductwork modifications to allow for installation of the high-temperature SCR control system prior to the HRSG bypass stack.

Cost effectiveness for the application of SCR technology to the repowering project CTG during simple-cycle mode was determined to be \$10,860 per ton of NO_x removed. This control cost is considered economically unreasonable. Table 5A-8 summarizes the results of the NO_x BACT analysis.

Table 5A-6. Capital Costs for SCR System—Simple-Cycle Mode

Item	Dollars		OAQPS Factor
<u>Direct Costs</u>			
Purchased equipment	2,384,000	(A)	
Instrumentation	238,400		$0.10 \times A$
Sales tax	143,040		$0.06 \times A$
Freight	119,200		$0.05 \times A$
Subtotal Purchase Equipment	**\$2,884,640**		B
Installation			
Foundations and supports	230,771		$0.08 \times B$
Handling and erection	403,850		$0.14 \times B$
Electrical	115,386		$0.04 \times B$
Piping	57,693		$0.02 \times B$
Insulation for ductwork	28,846		$0.01 \times B$
Painting	28,846		$0.01 \times B$
Subtotal Installation Cost	**\$865,392**		
Subtotal Direct Costs	**\$3,750,032**		
<u>Indirect Costs</u>			
Engineering	288,464		$0.10 \times B$
Construction and field expenses	144,232		$0.05 \times B$
Contractor fees	288,464		$0.10 \times B$
Start-up	57,693		$0.02 \times B$
Performance test	28,846		$0.01 \times B$
Contingency	86,539		$0.03 \times B$
Subtotal Indirect Costs	**\$894,238**		
TOTAL CAPITAL INVESTMENT	**\$4,644,270**	(TCI)	

Sources: Engelhard, 1999.
ECT, 1999.

Table 5A-7. Annual Operating Costs for SCR System—Simple-Cycle Mode

Item	Dollars		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	15,549	(A)	@ $28.40/hr
Supervisor	2,332		0.15 × A
Maintenance			
Labor	16,759	(B)	@ $30.61/hr
Materials	16,759		1.00 × B
Subtotal Labor, Material, and Maintenance Costs	**$51,399**	**(C)**	
Catalyst costs			
Replacement (materials and labor)	$1,667,260		Vendor quote + labor + freight + sales tax
Annualized Catalyst Costs	**$425,863**		8.75% @ 5 yrs
Raw materials and utilities			
Electricity	9,497		
Aqueous NH_3	77,899		
Subtotal Raw Materials and Utilities	**$87,396**		
Energy penalties			
Turbine backpressure	130,874		0.6% penalty
Subtotal Direct Costs	**$695,532**	(TDC)	
Indirect Costs			
Overhead	30,840		0.60 × C
Administrative charges	92,885		0.02 × TCI
Property taxes	46,443		0.01 × TCI
Insurance	46,443		0.01 × TCI
Capital recovery	464,950		8.75% @ 5 yrs
Subtotal Indirect Costs	**$681,561**		
TOTAL ANNUAL COST	**$1,377,093**		

Sources: Engelhard, 1999.
GRU, 1999.
ECT, 1999.

Table 5A-8. Summary of NO_x BACT Analysis—Simple-Cycle Mode

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
SCR	18.4	80.4	126.8	4,644,270	1,377,093	10,860	14,885	Y	Y
Baseline	47.3	207.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,760 hr/yr gas-firing and 1,000 hr/yr oil-firing.

Sources: GE, 1999.
GRU, 1999.
ECT, 1999.

5A.5.2 PROPOSED BACT EMISSION LIMITATIONS

At baseload operation and 59° F ambient temperature during natural gas firing, maximum NO_x exhaust concentration and hourly mass emission rate from the CTG for both simple- and combined-cycle modes of operation will be 9.0 ppmvd and 32.0 lb/hr, respectively, based on the application of DLN combustors. At baseload operation and 59° F ambient temperature during distillate fuel oil firing, maximum NO_x exhaust concentration and hourly mass emission rate from the CTG for both simple- and combined-cycle modes of operation will be 42 ppmvd and 166.0 lb/hr, respectively, based on the use of wet injection. Table 5A-9 summarizes the NO_x BACT emission limits proposed for the repowering project. NO_x emission rates proposed as BACT for the repowering project CTG are consistent with recent FDEP BACT determinations.

5A.5.3 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5A-10 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5A-11 summarizes specific proposed BACT emission limits for each pollutant.

Table 5A-9. Proposed NO_x BACT Emission Limits—Simple- and Combined-Cycle Modes

Emission Source	Proposed NO_x BACT Emission Limits*	
	lb/hr*	ppmvd†
GE PG 7121 (7EA) CTG (Natural Gas firing)	32	9
GE PG 7121 (7EA) CTG (Distillate Fuel Oil firing)	166	42

*At ISO conditions.
†Corrected to 15-percent O_2.

Sources: GE, 1999.
ECT, 1999.

Table 5A-10. Summary of BACT Control Technologies—Simple- and Combined-Cycle Modes

Pollutant	Control Technology
GE PG7121 (7EA) CTG	
PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil. • Efficient combustion.
CO	• Efficient combustion.
NO_x	• Use of advanced dry low-NO_x burners (natural gas firing). • Use of wet injection (distillate fuel oil firing).

Source: ECT, 1999.

Table 5A-11. Summary of Proposed BACT Emission Limits—Simple- and Combined-Cycle Modes

Emission Source	Pollutant	Proposed BACT Emission Limits ppmvd	lb/hr
GE PG7121 (7EA) CTG (Natural Gas firing)			
	PM_{10}	10-percent opacity	
	CO*	25	54†
	CO	20	43†
	NO_x	9**‡	32†
GE PG7121 (7EA) CTG (Distillate Fuel Firing)			
	PM_{10}	10-percent opacity	
	CO	20	43†
	NO_x	42**‡	166†

*First year operation.
†At ISO conditions.
**Corrected to 15 percent O_2.
‡24-hour block average.

Sources: GE, 1999.
ECT, 1999.

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 6, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Michael L. Kurtz – General Manager
Designated Representative
Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32614-7117

Re: DEP File Nos. 0010005-002-AC and PSD-FL-276
GRU - J.R. Kelley Power Plant – Repowering Project

Dear Mr. Kurtz:

On September 7, the Department received Gainesville Regional Utilities (GRU)'s application and complete fee for an air construction permit for the 136 MW Repowering project at the J.R. Kelly Power Station in Alachua County. Based on our initial review of the application, the application is incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Please submit a BACT analysis for the proposed combustion turbine operating in a simple cycle mode.

We are waiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Teresa M. Heron (review engineer) at 850/921-9529.

Sincerely,

A A Linero 10/6

A.A. Linero, P.E. Administrator
New Source Review Section

AAL/th

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
Tom Davis, P.E. ECT
Chris Kirts, DEP-NED
Yolanta Jonynas, GRU

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

October 6, 1999

Re: PSD-FL-276

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for Gainesville Regional Utilities' (GRU) proposed repowering of its J. R. Kelly Generating Station in Gainesville, Florida. The facility is located 102 km south of Okefenokee Wilderness and 103 km northeast of Chassahowitzka Wilderness, both Class I air quality areas administered by the Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. In summary, GRU's best available control technology analysis is incomplete. We recommend that GRU be required to adequately consider SCONOx (trademark name of Goal Line Environmental Technologies) or selective catalytic reduction to control emissions of nitrogen oxides.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2617.

Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

Enclosures

cc: D. Heron
P. Reynolds, NED Branch
C. Kirts, NED
C. Bird, Alachua Co.
Y. Gonynas, GRU

Technical Review of
Prevention of Significant Deterioration Permit Application
For Gainesville Regional Utilities
J.R. Kelly Generating Station
PSD-FL-276
Gainesville, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
September 28, 1999

Gainesville Regional Utilities (GRU) is proposing to re-power its existing J.R. Kelly Generating Station in Gainesville, Florida by the addition of a General Electric 7EA combined-cycle gas/oil turbine. The facility is located 102 km south of Okefenokee Wilderness and 103 km northeast of Chassahowitzka Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service. The proposed project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), fine particulate matter less than 10 microns in diameter (PM-10), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	113
PM-10	23
CO	213

Because of the relatively small emissions increases, the potential for impacts to the air quality and air quality related values of the Class I areas is minimal. However, we are interested in ensuring that best available control technology (BACT) is applied in a consistent manner throughout the country.

Best Available Control Technology (BACT) Review

We believe that BACT for NO_x emissions from this turbine is selective catalytic reduction (SCR) or SCONOx (trademark name of Goal Line Environmental Technologies). However, GRU proposes to limit NO_x emissions by dry low-NO_x combustors when firing natural gas (to 9 ppm) and water injection (to 42 ppm) when firing oil. GRU's BACT analysis is incomplete in several respects, summarized below.

A true "top-down" approach was not used because it did not start with lowest achievable emission rate (LAER). LAER should not be greater than 2.5 ppm NO_x for a gas turbine; GRU started at 3.5 ppm.

In addition, GRU rejected SCONOx control technology as being technically infeasible "because the technology has not been commercially demonstrated on a large CTG [combustion turbine generator]."

SCONOx is now technically feasible. A permit requiring SCONOx was issued on May 29, 1999, by EPA Region IX and the San Joaquin Valley Unified Air Pollution Control District to Pacific Gas & Electric for a 262 MW turbine at its La Paloma Power Generating Project near Bakersfield, California. According to EPA's New Source Review Workshop Manual, "a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type." Because SCONOx is now commercially available for large gas turbines, it is technically feasible. The GRU BACT analysis can not be considered complete until it addresses the economic and environmental feasibility of this option.

GRU also rejected SCR on the premise that it is not economically feasible and because of purported adverse environmental impacts. The analysis of economic feasibility for SCR contains several errors:

- An additional cost for instrumentation should not be included for an SCR system designed to operate at such a low (61%) efficiency. Conversations with the SCR vendor have indicated that standard instrumentation included with the basic equipment is sufficient to maintain this level of efficiency.
- The interest rate used to calculate the Capital Recovery Factor is greater than the 7% value recommended by the EPA OAQPS Control Cost Manual and EPA Region IV.
- The Heat Rate Penalty is greater than the 0.5% recommended by EPA.

When we re-calculated the economics of SCR for this application using standard EPA techniques and assumptions for electricity and ammonia costs representative of the Florida area, we estimated a cost of slightly less than $4,000 per ton of NO_x removed (tables enclosed). It is likely that, if a more efficient catalyst were evaluated to reduce NO_x emissions to the 2.5 ppm level now representative of LAER, the cost per ton would be even less.

Environmental impacts have not been documented and are not supported. If GRU is to claim significant harmful emissions of ammonia and ammonia compounds, it must show quantitatively and qualitatively, using actual measurements and verifiable estimation techniques, that these emissions are likely to occur and present an adverse environmental impact. Applicants who propose SCR typically state that the types of "problems" cited by GRU can be prevented by good operation and maintenance practices.

Conclusions and Recommendations

- GRU's BACT analysis is incomplete because it improperly dismissed SCONOx.

- GRU's BACT analysis is deficient because it did not properly evaluate the economic and environmental feasibility of SCR.

We believe that SCR or SCONOx represent BACT for this application.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Kelly Generating Station
Table 1.a
Plant Data

				Capacity	
Site	FWS Area(s)	Source		(mmBtu/hr)	(MW)
Kelly Station, Gainesville, GA	OKEF	1	CCT	1120	80+40
				each	each

Given/Assumptions

Source	CCT
Exhaust gas flow (lb/Hr)	2,602,800
Exhaust gas flow (acfm)	887,436
Basic Equipment Costs	$710,000
Ammonia storage cost	$39,000
Uncontrolled Emission rate (TPY)	207
Control efficiency (%)	61%
Operating Hours per Year	8,760
Operating Hours per Shift	8
Operating Shifts per Year	1095
Operating Labor Cost ($/hr)	28.4
Maintenance Labor Cost ($/hr)	30.61
Electrical Cost ($/kWh)	$0.04
Reagent Use (lb NH3/lb NOx)	0.6
Reagent Costs ($/T)	$220
Electrical efficiency	90%
Catalyst replacement	$350,000
Catalyst disposal ($/Yr)	$25,000
Catalyst life (Yr)	5
Heat rate penalty (% of MW output)	0.5%
Ammonia slip (ppm)	5
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Kelly Generating Station

Table 1.b

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item		Factor	Cost
Direct Costs			CCT
Purchased equipment costs			
SCR + auxiliary equipment			$710,000
Sales taxes		0.06 A	$42,600
Freight		0.05 A	$35,500
Purchased equipment cost, PEC	B=	1.11 A	$788,100
Direct installation costs			
Foundations & supports		0.08 B	$63,048
Handling & erection		0.14 B	$110,334
Electrical		0.04 B	$31,524
Piping		0.02 B	$15,762
Insulation		0.01 B	$7,881
Painting		0.01 B	$7,881
Direct installation costs		0.30 B	$236,430
Site preparation	As required, SP		$0
Buildings	As required, Bldg.		$0
Total Direct Costs, DC		1.30 B+SP+Bldg	$1,024,530
Indirect Costs (installation)			
Engineering		0.10 B	$78,810
Construction and field expenses		0.05 B	$39,405
Contractor fees		0.10 B	$78,810
Start-up		0.02 B	$15,762
Performance test		0.01 B	$7,881
Contingencies		0.03 B	$23,643
Total Indirect Cost, IC		0.31 B	$244,311
Total Capital Investment = DC + IC		1.61 B+SP+Bldg	$1,268,841

Kelly Generating Station
Table 1.c
Annual Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor				Cost
Direct Annual Costs, DC					CCT
Operating labor					
Operator		0.5 hr/shift			$15,549
Supervisor		15% of operator			$2,332
Operating materials					
Reagent	0.6 T NH3/T NOx	207 TPY NOx/0.23 Aqueous NH3*		220 $/T =	$27,324
Maintenance					
Labor		0.5 hr/shift			$16,759
Material		100% of maintenance labor			$16,759
Catalyst replacement					$70,000
Electricity	18 lb/hr *	518.1 Btu/lb*	0.000293 kW*hr/Btu*		
	0.04 $/kWh*	8,760 hr/yr*	0.90 ef. =		$772
Total DC					$148,723
Energy Costs					
Heat rate penalty		80 MW *	8,760 hr/yr *		
		1000 kW/MW *	0.005 loss *	0.04 $/kWh =	$122,640
Indirect Annual Costs, IC					
Overhead	60% of maintenance costs				$47,234
Administrative charges	2% of Total Capital Investment				$25,377
Property tax	1% of Total Capital Investment				$12,688
Insurance	1% of Total Capital Investment				$12,688
Capital recovery		0.1098 * [Total Capital Investment-(1+		0.11)(Cat Cost)]	$130,781
Total IC					$228,768
Total Annual Cost		DC + IC			$500,132

Kelly Generating Station
Table 1.d
Cost Effectiveness

Source	CCT	Units
Pollutant	NOx	
Uncontrolled emissions	207	TPY
Control efficiency	61%	
Controlled emissions	81	TPY
Pollutants removed	126	TPY
Annual cost	$500,132	/yr
Annual cost - Emission fees saved	$496,344	@ $30/T
Cost/ton	$3,961	/T

Kelly Generating Station
Table 1.e
Environmental Impacts of SCR at 61% removal

NOx removed	126 TPY	
Ammonia released	34 TPY @	5 ppmv

5 ppmvd NOx* E-06 * (20.9/(20.9- 15 % O2)) * 17 MW NH3 * 8740 dscf/mmBtu (fuel input) F-factor(gas)/ 385 scf/lb-mole (vol/mol ratio) = 0.007 lbm/mmBtu

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 6, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Michael L. Kurtz – General Manager
Designated Representative
Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32614-7117

Re: DEP File Nos. 0010005-002-AC and PSD-FL-276
GRU - J.R. Kelley Power Plant – Repowering Project

Dear Mr. Kurtz:

On September 7, the Department received Gainesville Regional Utilities (GRU)'s application and complete fee for an air construction permit for the 136 MW Repowering project at the J.R. Kelly Power Station in Alachua County. Based on our initial review of the application, the application is incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Please submit a BACT analysis for the proposed combustion turbine operating in a simple cycle mode.

We are waiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Teresa M. Heron (review engineer) at 850/921-9529.

Sincerely,

A.A. Linero 10/6

A.A. Linero, P.E. Administrator
New Source Review Section

AAL/th

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
Tom Davis, P.E. ECT
Chris Kirts, DEP-NED
Yolanta Jonynas, GRU

BEST AVAILABLE COPY

Z 031 392 015

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to: Michael Kurtz	
Street & Number: GRU	
Post Office, State, & ZIP Code: Gainesville 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: 10-6-99 0010005-002-AC PSD-Fl-276	

PS Form **3800**, April 1995

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:
Michael Kurtz, Gen. Mgr.
GRU
PO Box 147117 (A134)
Gainesville Fl
32614-7117

4a. Article Number
Z 031 392 015

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

7. Date of Delivery
OCT 08 1999

5. Received By: *(Print Name)*

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

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

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

Domestic Return Receipt

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning Department

September 15, 1999

Mr. Alvaro Linero, Administrator
New Source Review
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

Re: Gainesville Regional Utilities
J.R. Kelly Generating Station - Repowering Project
Application for Air Construction Permit and Title V Operating Permit Revision

Dear Mr. Linero:

By letter dated September 3, 1999 Gainesville Regional Utilities (GRU) submitted to the Department the above-referenced permit applications. As GRU would like to commence construction of the new unit by February 2000, it is of utmost importance to GRU to obtain the Air Construction Permit as expeditiously as possible. Therefore, GRU is requesting that the Department process the above-referenced permits individually and not contemporaneously as originally envisioned.

GRU appreciates your assistance in this matter. Please call me at (352) 334-3400 Ext. 1284 if you have any questions or need additional information.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Electric Utility Environmental Engineer

xc: D. Beck
D. DuBose
R. Klemans
M. Kurtz
S. Manasco
B. Mitchell, FDEP- Tall.
E. Regan
S. Sheplak, FDEP - Tall.
G. Swanson
JRK CC1

jrkcc1permit91599.y31

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 8, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: GRU Kelly Generating Station
Combined Cycle Repowering Project
PSD-FL-276

Dear Mr. Worley:

Enclosed for your review and comment is an application for the GRU Kelly Generating Station Repowering Project in Gainesville, Alachua County. This project will be comprised of: a nominal 83 MW dual fuel GE PG7121EA combustion turbine; a heat recovery steam generator capable of raising enough steam to produce another 40 MW through the existing Unit 8 steam turbine-electrical generator; and two stacks for simple and combined cycle operation. GRU proposes full time operation of the unit and up to 1000 hours of 0.05 percent sulfur No. 2 distillate fuel oil.

The site is approximately 102 kilometers South of the Okeefenokee National Wildlife Area and 103 kilometers Northeast of the Chassahowitzka National Wildlife Area. The applicant proposes NO_X emissions at 9 ppmvd on natural gas and 42 ppmvd on fuel oil with net annual emissions increases (corrected for reductions from repowered unit) as per the table below:

Pollutant	Proposed Project Emissions (tons per year)
NO_X	113
SO_2	18
CO	171
H_2SO_4 Mist	5
PM/PM_{10}	23
VOC	7

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. If you have any questions, please contact Teresa Heron at (850) 921-9529.

Sincerely,

AA Linero 9/8

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/al

Enclosures

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning Department

VIA AIRBORNE EXPRESS

September 3, 1999

RECEIVED
SEP 07 1999
BUREAU OF AIR REGULATION

Mr. Al Linero, Administrator
New Source Review
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station Repowering Project
Applications for Air Construction Permit and Title V Operating Permit Revision

0010005-002-AC
PSD-FL-276

Dear Mr. Linero:

Enclosed are eight (8) copies of the above-referenced permit applications and a check (Check No. 81709) in the amount of $ 7,500.00 in payment of the air construction permit application fee. It is my understanding that the Department will be distributing the permit applications to EPA, the FDEP NE District and Gainesville Branch offices, Alachua County Environmental Protection Dept. and the National Park Service.

Please call me at (352) 334-3400 Ext. 1284 or Mr. Tom Davis at (352) 332-6230 Ext. 351 if you have any questions or need additional information.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Electric Utility Environmental Engineer

xc: D. Beck
D. DuBose, wo. enc.
R. Klemans, wo. enc.
M. Kurtz
S. Manasco,wo. enc.
E. Regan, wo.enc.
G. Swanson
JRK CC1

jrkcc1permitdep.y30

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 8, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Re: GRU Kelly Generating Station
Combined Cycle Repowering Project
PSD-FL-276

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the GRU Kelly Generating Station Repowering Project in Gainesville, Alachua County. This project will be comprised of: a nominal 83 MW dual fuel GE PG7121EA combustion turbine; a heat recovery steam generator capable of raising enough steam to produce another 40 MW through the existing Unit 8 steam turbine-electrical generator; and two stacks for simple and combined cycle operation. GRU proposes full time operation of the unit and up to 1000 hours of 0.05 percent sulfur No. 2 distillate fuel oil.

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Sincerely,

A A Linero 9/8

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/al

Enclosures

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning Department

VIA AIRBORNE EXPRESS

September 3, 1999

RECEIVED
SEP 07 1999
BUREAU OF AIR REGULATION

Mr. Al Linero, Administrator
New Source Review
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station Repowering Project
Applications for Air Construction Permit and Title V Operating Permit Revision

0010005-002-AC
PSD-FL-276

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Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Electric Utility Environmental Engineer

xc: D. Beck
D. DuBose, wo. enc.
R. Klemans, wo. enc.
M. Kurtz
S. Manasco,wo. enc.
E. Regan, wo.enc.
G. Swanson
JRK CC1

jrkcc1permitdep.y30

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning Department

VIA AIRBORNE EXPRESS

September 3, 1999

RECEIVED
SEP 07 1999
BUREAU OF AIR REGULATION

Mr. Al Linero, Administrator
New Source Review
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station Repowering Project
Applications for Air Construction Permit and Title V Operating Permit Revision

0010005-002-AC
PSD-FL-276

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Sincerely,

Yolanta E. Jonynas

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M. Kurtz
S. Manasco,wo. enc.
E. Regan, wo.enc.
G. Swanson
JRK CC1

jrkcc1permitdep.y30

P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1260 Fax: (352) 334-3151

81709

CITY OF GAINESVILLE
GAINESVILLE REGIONAL UTILITIES

0000081709 08/26/99 002878

INVOICE #	INVOICE DATE	PURCHASE ORDER #	INVOICE AMOUNT	DISCOUNT	NET AMOUNT
082599	08/25/99		7,500.00	0.00	7,500.00
Air construction Permit Application Fee - J.R. Kelly Generating Station Repowering Project					
			7,500.00	0.00	7,500.00

DETACH HERE BEFORE DEPOSITING CHECK

THE FACE OF THIS DOCUMENT HAS A MULTICOLORED BACKGROUND ON WHITE PAPER

GRU

CITY OF GAINESVILLE
GAINESVILLE REGIONAL UTILITIES
GAINESVILLE, FLORIDA

[redacted] 81709

08/26/99

SUNTRUST/SOUTH CENTRAL FLORIDA, N.A.
OKEECHOBEE OFFICE
OKEECHOBEE, FL 34974

PAY ONLY SEVEN 7 FIVE 5 ZERO 0 ZERO 0 00 CTS CTS

SEVEN THOUSAND FIVE HUNDRED DOLLARS AND 00 CENTS ***********

******$7,500.00

PAY TO THE ORDER OF

Dept of Env. Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2405

CONTROLLED DISBURSEMENT ACCOUNT

Michael L Kurtz

VOID OVER $7,500.00 VOID AFTER 180 DAYS

FORM NO. 9704L

[redacted]

Z 031 391 868

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Michael Kurtz	
Street & Number GRU	
Post Office, State, & ZIP Code Gainesville 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 0010005-002AC 2-24-00 PSO-FI-276	

PS Form **3800**, April 1995

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- 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.
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- 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. Michael Kurtz, Gen. Mgr.
City of Gainesville, GRU
PO Box 147117
Gainesville, Fl
32614-7117

4a. Article Number
Z 031 391 868

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

7. Date of Delivery
0725

GAINESVILLE FL REGISTRY SECT FEB 28 2000 USPS

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X Bill Tippenkotter

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

Form **3811**, Dec. 1994 102595-98-B-0229 Domestic Return Receipt

Is your **RETURN ADDRESS** completed on the reverse side?

Thank you for using Return Receipt Service.

5 Legal Notice

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Alachua 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 Gainesville Regional Utilities. The permit is to construct a nominal 83 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine generator at the existing J.R. Kelly Generating Station in downtown Gainesville, Alachua County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM10) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Gainesville Regional Utilities (GRU), Post Office Box 147117, Gainesville, Florida 32614-7117.

The proposed unit (Combined Cycle Unit CC-1) is a General Electric PG7121EA combustion turbine-electrical generator with an unfired heat recovery steam generator that will raise sufficient steam to produce approximately another (maximum) 50MW via the existing Unit 8 steam-driven electrical generator. Upon installation of the new proposed unit, the Unit 8 steam boiler will permanently cease operation. Distillate oil will be used as back up fuel and limited to a 1000 hours per year. The turbine will be able to operate in simple cycle (i.e. without HRSG or steam-electrical turbine). The project also includes: a 78 foot stack for simple cycle operation; a 100 foot stack for combined cycle operation; and a cooling tower (existing).

Emission of PM10 and CO will be controlled by good combustion of clean pipeline supplied natural gas or maximum 0.05 percent sulfur distillate fuel oil. The BACT determination for CO is 20 parts per million by volume (ppmvd). Typical expected CO emissions are 5-10 ppmvd. The BACT determination for PM10 is 5 pounds per hour (lb/hr) while burning natural gas and 10 lb/hr while burning fuel oil with a visible emission limitation of 10 percent opacity. Nitrogen oxides (NOx) emissions will be controlled by Dry Low NOx technology capable of achieving 9 parts per million by volume (ppmvd) at 15 percent oxygen while firing natural gas and by wet injection achieving 42 ppmvd @ 15% O2 when burning fuel oil. Sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC) will be controlled by good combustion of inherently clean fuels.

PSD and BACT do not apply for NOx, SO2, SAM, PM and VOC emissions. The maximum future potential (i.e., permitted allowable) annual emissions in tons per year are summarized below for comparison with recent past actual annual emissions from Unit 8 which is slated for retirement. The increases shown are based on future potential emissions minus past actual emissions.

Pollutant	Unit 8 (present potential)	Unit 8 (past actual)	CC-1 (future potential)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25
PM10	296	1.8	24.4	22.6	15
SAM	160	1.3	5.4	4.1	7
202	6,496	29	47.1	18	40
NOx	1050	94	133 (cap)	39	40
VOC	12	2	9.2	7	40
CO	78	18	231 (yr 1)	213 (yr 1)	100
CO	78	18	189 (yr 2+)	189 (yr 2+)	100

The modest maximum increases in actual emissions and the very substantial reduction in total potential emissions will accompany a tripling of generation capacity compared with the existing Unit 8 and as much as a six-fold increase in actual power generation. The Department and GRU agreed to an emission cap for Unit CC-1 such that the total NOx increase will be less than 40 TPY and thus exempt from PSD for that pollutant.

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 issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air

5 Legal Notice

Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice. The Department will hold a public meeting to explain the proposed permitting action and receive public comments. The meeting will be held from 7 to 9 p.m. on January 12, 2000 at the GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue in Gainesville.

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 notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida
904/448-4300
Fax: 904/448-4363

Dept. of Environmental Protection
Northeast District Branch
101 NW 75 Street, Suite 3
Gainesville, Florida 32607
Telephone: 352/333-2850
Fax: 352/333-2856

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.

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Kim Jober

2. MS 5500

3. ______

4. ______

5. ______

PLEASE PREPARE REPLY FOR:

_____ SECRETARY'S SIGNATURE

_____ DIV/DIST DIR SIGNATURE

_____ MY SIGNATURE

_____ YOUR SIGNATURE

_____ DUE DATE _____

ACTION/DISPOSITION

_____ DISCUSS WITH ME

_____ COMMENTS/ADVISE

_____ REVIEW AND RETURN

_____ SET UP MEETING

_____ FOR YOUR INFORMATION

_____ HANDLE APPROPRIATELY

_____ INITIAL AND FORWARD

_____ SHARE WITH STAFF

_____ FOR YOUR FILES

COMMENTS:

FROM: ______ DATE: ______ PHONE: ______

DEP 15-026 (12/93)

Z 031 391 906

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Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Gregg Worley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
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 12-20-99 GRU 050-FI-276	

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. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
Z 031 391 906

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

7. Date of Delivery

5. Received By: *(Print Name)*
JOYCE EVANS

6. Signature: *(Addressee or Agent)*
X DEC 22 1999

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

Thank you for using Return Receipt Service.

PS Form 3811, December 1994 102595-98-B-0229 Domestic Return Receipt

Z 031 391 905

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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

Sent to Michael Kurtz	
Street & Number GRU	
Post Office, State, & ZIP Code Gainesville 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 12-17-99 C010005-002-AC PSD-FI-276	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

- 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.

...he followi... an extra fee):

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

Consult postmaster for fee.

3. Article Addressed to: Michael Kurtz City of Gainesville, GRU P O Box 147117 (A134) Gainesville, Fl 32614-7117	4a. Article Number Z 031 391 905 4b. Service Type ☐ Registered ☒ Certified ☐ Express Mail ☐ Insured ☐ Return Receipt for Merchandise ☐ COD 7. Date of Delivery DEC 20 1999
5. Received By: *(Print Name)* Lanay Smith	8. Addressee's Address *(Only if requested and fee is paid)*
6. Signature: *(Addressee or Agent)* X Lanay Smith	

PS Form **3811**, December 1994 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 031 392 015

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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

Sent to Michael Kurtz	
Street & Number GRU	
Post Office, State, & ZIP Code Gainesville 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 10-6-99 0010005-002-AC PSD-F1-276	

PS Form **3800**, April 1995

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:
Michael Kurtz, Gen. Mgr.
GRU
PO Box 147117 (A134)
Gainesville Fl
32614-7117

4a. Article Number
Z 031 392 015

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

7. Date of Delivery
OCT 08 1999

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X Bill Lippincott

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

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

229 Domestic Return Receipt

PSD-FL-276 PERMITTING HISTORY

Gainesville Regional Utility | **Facility ID No.: 0010005**
City of Gainesville

PSD Permit History (for tracking purposes):

Permit No.	Issue Date	PERMITTING ACTION DESCRIPTION
PSD-FL-276 0010005-002	2/24/00	To construct/install one 133 MW combined cycle unit. Allowed to operate in simple cycle mode. Primary fuel: NG. Back-up: 0.05 % fuel oil for 1000 hr/yr. Non- PSD review for NOx: cap of 133 TPY.

Check Sheet

Company Name: Gainesville Regional Utilities
Permit Number: 0010005-002-AC
PSD Number: 276
Permit Engineer: Teresa Heron + Al Linero

Application:

- [x] Initial Application -on Shelf - notebook
  - [x] Incompleteness Letters
  - [x] Responses
  - [ ] Waiver of Department Action
  - [x] Department Response
  - [ ] Other

Cross References:

- [ ]
- [ ]
- [ ]

Intent:

- [x] Intent to Issue
- [x] Notice of Intent to Issue
- [x] Technical Evaluation
- [x] BACT Determination
- [x] Unsigned Permit
- Correspondence with:
  - [x] EPA
  - [x] Park Services
  - [x] Other
- [x] Proof of Publication
  - [ ] Petitions - (Related to extensions, hearings, etc.)
  - [ ] Waiver of Department Action
  - [x] Other

Final Determination:

- [x] Final Determination
- [x] Signed Permit
- [x] BACT Determination
  - [ ] Other

Post Permit Correspondence:

- [ ] Extensions/Amendments/Modifications
- [ ] Other