GRU

GAINESVILLE REGIONAL UTILITIES

VIA FAX

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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 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 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

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

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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)]

no support in Rules & very punitive in nature

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.]

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

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

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

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

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

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

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.]

12-month rolling

- 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. [Rule 62-4.070, F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.] (annual #/MMBtu x annual heat input)

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 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.]

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

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~~s~~ 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 agreed 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.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION III - EMISSIONS UNIT SPECIFIC 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 when firing natural gas 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

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.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION III - EMISSIONS UNIT SPECIFIC CONDITIONS

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. 39

36. Excess Emissions Report: If excess emissions occur (as specified in Condition ~~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 dealt w. malfn. 2 hrs. 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)

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 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.

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- 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)]

no support in Rules & very punative 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.]

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

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 B. 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

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

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 E. 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 1
③ Public Notice - pg 1
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~~ Gainesville ~~Commission Chambers, etc.etc.etc.~~
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

ECT
Environmental Consulting & Technology, Inc.

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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.)*

Response

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

ECT
Environmental Consulting & Technology, Inc.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8960

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NOV 10 1999

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

ECT

Environmental Consulting & Technology, Inc.

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BUREAU OF AIR REGULATION

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 re-evaluated 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 2.2 ppmvd 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 (^{o}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, 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.

Energy Impacts

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 2.2 ppmvd 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.

ECT
Environmental Consulting & Technology, Inc.

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					
Pollutant Name	Fuels	Hours/Year	Standards	lbs./hour	TPY	[redacted]	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				62-296.405(1)(b), F.A.C.	III.B.6.
PM(SB)**	Nos. 4, 5, 6 F.O.	1095	0.3 lb/MMBtu				62-210.700(3), F.A.C.	III.B.7.
SO2	Nos. 4, 5, 6 F.O.	8760	2.75 lb/MMBtu				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	F&WS	F&WS (adjusted)[1]	GRU	% Difference[2]	% Difference[3]	Comment
	Costs ($)					
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.

RECEIVED

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)
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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
<u>Direct Costs</u>		
Purchased equipment	766,000	A
Sales tax	45,960	0.06 × A
Instrumentation	76,600	0.10 × A
Freight	38,300	0.05 × A
Subtotal Purchased Equipment	**$926,860**	**B**
Installation		
Foundations and supports	74,149	0.08 × B
Handling and erection	129,760	0.14 × B
Electrical	37,074	0.04 × B
Piping	18,537	0.02 × B
Insulation for ductwork	9,269	0.01 × B
Painting	9,269	0.01 × B
Subtotal Installation Cost	**$278,058**	
Subtotal Direct Costs	**$1,204,918**	
<u>Indirect Costs</u>		
Engineering	92,686	0.10 × B
Construction and field expenses	46,343	0.05 × B
Contractor fees	92,686	0.10 × B
Start-up	18,537	0.02 × B
Performance test	9,269	0.01 × B
Contingency	27,806	0.03 × 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 Rates (tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	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
Direct Costs			
Purchased equipment	2,384,000	(A)	
Instrumentation	238,400		0.10 × A
Sales tax	143,040		0.06 × A
Freight	119,200		0.05 × A
Subtotal Purchase Equipment	**$2,884,640**		B
Installation			
Foundations and supports	230,771		0.08 × B
Handling and erection	403,850		0.14 × B
Electrical	115,386		0.04 × B
Piping	57,693		0.02 × B
Insulation for ductwork	28,846		0.01 × B
Painting	28,846		0.01 × B
Subtotal Installation Cost	**$865,392**		
Subtotal Direct Costs	**$3,750,032**		
Indirect Costs			
Engineering	288,464		0.10 × B
Construction and field expenses	144,232		0.05 × B
Contractor fees	288,464		0.10 × B
Start-up	57,693		0.02 × B
Performance test	28,846		0.01 × B
Contingency	86,539		0.03 × 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

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
Control Option	Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact (Y/N)	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	Proposed BACT Emission Limits 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.

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

RECEIVED
OCT 12 1999
BUREAU OF AIR REGULATION

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. Gonzalez, 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,

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

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)*

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

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

Is your RETURN ADDRESS completed on the reverse side?

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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

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

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

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

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

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

Printed on recycled paper.

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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R. Klemans, wo. enc.
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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

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning Department

VIA AIRBORNE EXPRESS

September 3, 1999

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jrkcc1permitdep.y30

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

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GRU

CITY OF GAINESVILLE
GAINESVILLE REGIONAL UTILITIES
GAINESVILLE, FLORIDA

63-115
631

81709

08/26/99

SUNTRUST/SOUTH CENTRAL FLORIDA, N.A.
OKEECHOBEE OFFICE
OKEECHOBEE, FL 34974

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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

⑈90181709⑈ ⑆063101153⑆69900500042528⑈