

STATE OF FLORIDA  
DEPARTMENT OF ENVIRONMENTAL PROTECTION  
NOTICE OF FINAL PERMIT

In the Matter of an  
Application for Permit by:

Walter P. Bussells, Chief Executive Officer  
Jacksonville Electric Authority  
21 West Church Street  
Jacksonville, Florida 32202-3139

DEP File No. 0310485-001-AC, PSD-FL-267  
Brandy Branch Facility  
Duval County

Enclosed is Final Permit Number 0310485-001-AC. This permit authorizes Jacksonville Electric Authority to construct the Brandy Branch facility. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.



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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 10-14-99 to the person(s) listed:

Walter P. Bussells, JEA \*  
N. Bert Gianazza, P.E., JEA  
Gregg Worley, EPA  
John Bunyak, NPS  
Chris Kirts, NED  
James L. Manning, P.E. RESD  
Anthony L. Compaan, Black & Veatch

Clerk Stamp

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

Keri Joken  
(Clerk)

10-14-99  
(Date)

Z 031 391 960

US Postal Service  
**Receipt for Certified Mail**

No Insurance Coverage Provided.

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Street & Number		SEA	
Post Office, State, & ZIP Code		Jacksonville 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		10-14-99	
0310485-001-AC			
PSO-FI-267			

PS Form 3800, April 1995

Is your RETURN ADDRESS completed on the reverse side?

**SENDER:**

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

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

- Addressee's Address
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Consult postmaster for fee.

3. Article Addressed to:  
 Walter Bussells  
 Jacksonville Electric A.  
 21 W. Church St.  
 Jacksonville, FL

4a. Article Number  
 Z 031 391 960

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

7. Date of Delivery  
 10-18-99

5. Received By: (Print Name)  
 32203-3139

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

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

Thank you for using Return Receipt Service.

## FINAL DETERMINATION

JEA

Brandy Branch/Baldwin City  
DEP File No.0310485, PSD-FL-267

The Department distributed a public notice package on August 12, 1999 to allow the applicant to construct a new plant known as the Brandy Branch Facility located at Baldwin City, Duval County. The Public Notice of Intent to Issue was published in The Florida Times-Union on August 23, 1999.

### COMMENTS/CHANGES

Comments were received from EPA by letter and facsimile correspondence dated September 10, 1999.

Comments were received from the Fish and Wildlife Service by letter dated August 30, 1999.

Comments were received from the applicant by electronic correspondences dated August 27 and September 24, 1999. Additionally, the Department received comments from the applicant requesting that the wording on the Public Notice be revised to reflect a maximum number of operating hours of 4750 of which 750 could be on oil. The Department agreed to the Public Notice change and will address the substantive issue herein.

EPA and the applicant commented on the Technical Evaluation and Preliminary Determination (TEPD), the BACT and the DRAFT Permit. The comments related to the BACT and permit are summarized below and the Department's responses are included following each comment. Comments related to the TEPD are noted and maintained in the file.

The Fish and Wildlife Service as well as the EPA commented on the need for CALPUFF modeling for visibility and regional haze in the (Class I) Okefenokee area. The applicant submitted this modeling on September 10, 1999 and (as indicated by FWS) the shutting down of the applicant's Southside Station along with the permitting of this new facility will cause a net benefit to visibility. A cumulative analysis, modeling all increment-consuming sources in the area, predicted SO<sub>2</sub> exceedances, which were not significantly contributed to by this facility. FDEP will investigate the matter to determine which sources are contributing significantly to the exceedances and develop possible remedies for further consideration..

### DRAFT Permit Administrative Requirements:

The applicant requested that the requirements listed as Conditions 6. and 7. ("Expiration" and "BACT Determination") be removed due to the inapplicability of 40 CFR 52.21 in the State of Florida.

RESPONSE: These conditions will remain, with changes to the referenced citations associated with these conditions.

### DRAFT Permit Specific Conditions:

1. *Specific Condition 4:* The applicant requested that the permit reflect the applicant's ability to install (optional) evaporative inlet cooling.

RESPONSE: The requested change will be accommodated, as this option was referenced in the Technical evaluation.

2. *Specific Condition 7:* The applicant requested that parenthesis be placed around the words "No. 2 or superior grade of distillate oil".

RESPONSE: The requested change will not be accommodated due to the possible inference that the adjective "superior" applies only to the grade of oil (No. 2) and not the sulfur content.

## FINAL DETERMINATION

JEA

Brandy Branch/Baldwin City  
DEP File No.0310485, PSD-FL-267

3. *Specific Condition 8:* The applicant requested that a permitting note be placed at the end of the condition, clarifying the Department's position on the purpose of heat input values.

RESPONSE: The following language is added to the end of the condition, as has been done in other permitting actions: {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 95-100 percent of the emissions unit's rated 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.....}

4. *Specific Condition 13:* The applicant requested that the condition be reworded to clearly indicate total hours of permitted use and to be consistent with all modeling. Additionally, the EPA indicated a lack of clarity in hours of operation per combustion turbine and recommended that the use of the words "a calendar year" be replaced so as to be consistent with other permit conditions.

RESPONSE: The permit condition is reworded as follows: 13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

5. *Specific Conditions 14 and 15:* The applicant requested that these conditions be deleted. The EPA commented that limits should be on an individual combustion turbine basis. These conditions had required facility-wide fuel usage monitoring and reporting on a monthly basis.

RESPONSE: The aforementioned permit conditions are deleted as the newly worded Specific Condition 13 dictates a precise (and different) method of compliance per combustion turbine.

6. *Specific Condition 17:* The applicant requested that this condition be deleted. The EPA commented that the related NO<sub>x</sub> limits should be lower and have shorter compliance times.

RESPONSE: This condition requires that the units be constructed so as to be easily capable of accommodating an SCR should one be required in order to meet the NO<sub>x</sub> limits. Given that the applicant initially requested a NO<sub>x</sub> limit of 12 ppm and that the Department has imposed a more stringent limit of 10.5 ppm, this condition will not be deleted.

7. *Specific Condition 20:* The applicant requested language changes to accurately reflect the purpose and basis of the chart, noting that a BACT analysis was not required for VOC.

RESPONSE: A note will be added below the chart indicating that the VOC limit was not determined by BACT.

8. *Specific Condition 21:* The EPA suggested that the limits imposed by the second "bullet" be more stringent. The EPA additionally commented on the applicability of SCR (as discussed in the BACT) questioning several of the applicant's assumptions (through its comments 4., 5. and 6.). The applicant requested that the condition imposed by the fourth "bullet" (requirement to evaluate lower NO<sub>x</sub> emissions while firing oil) be deleted or reworded.

RESPONSE: The limits imposed by the second bullet are related to NO<sub>x</sub> emissions while firing natural gas. The Department appreciates the concerns raised by the EPA, but believes that extenuating circumstances are involved. Namely, these are:

## FINAL DETERMINATION

JEA  
Brandy Branch/Baldwin City  
DEP File No.0310485, PSD-FL-267

1) The applicant has proposed to shutdown an existing facility (Southside) in an effort to offset most air emission-related issues. The result should yield a net reduction of regulated pollutants emitted on an annual basis.

2) By imposing a limit of 10.5 ppm (versus 12 ppm as proposed by the applicant), the Department estimates that the net NO<sub>x</sub> emissions of the combined actions noted above are approximately zero TPY. Further mandated NO<sub>x</sub> reductions may be viewed as punitive.

3) In order to accommodate the applicant's concern about their ability to routinely achieve this lower imposed limit as well as the applicant's action noted in 1) above, the Department believes that a compliance method which is more flexible than is normally required can be allowed.

Therefore, the limits imposed by the second bullet will not be changed. However, the BACT will incorporate these extenuating circumstances as a part of the Department's justification. Concerning the applicant's request on the fourth "bullet", the wording will be revised in a fashion similar to that proposed by the applicant.

9. *Specific Condition 22:* The applicant requested that EPA method 10 be clearly indicated as the method of compliance for both the concentration and lb/hr limit of CO emissions. The applicant additionally noted that vendor guarantees for CO have only been obtained at the 15 ppm level, versus the 12 ppm level identified in the draft BACT. The applicant indicated that reasonable assurance for a 12 ppm emission rate cannot be provided and requested the ability to evaluate a lower limit (via testing and analysis) after the initial (15 ppm) acceptance test and subsequent testing is completed.

RESPONSE: Language similar to that proposed by the applicant for EPA Method 10 will be added. Concerning the CO limit, permit language will be included (similar to what is shown in Specific Condition 21 (fourth bullet)) including an "initial" 15 ppm limit with a requirement to submit an evaluation to FDEP concerning a lower limitation.

10. *Specific Condition 24:* The EPA requested that the permit conditions should list the corresponding particulate matter emissions rate limit even though opacity will be used as the method of compliance. Additionally, the EPA questioned the allowance of 20% opacity during startup and shutdown, noting that FDEP routinely permits combustion turbines without this "automatic" allowance.

RESPONSE: The Department agrees with EPA and will revise this condition accordingly.

11. *Specific Condition 26:* The applicant requested that an assumed typographical error be corrected in this condition.

RESPONSE: The typographical error will be corrected.

12. *Specific Condition 27:* The applicant requested that compliance-related notifications should be made to RESD and not duplicated to the Department. Additionally, the applicant requested that the condition be revised to accurately reflect Rule 62-210.700(6), F.A.C.

RESPONSE: Administrative Requirement number 13 as well as Specific Conditions 6, 27, 35, 37 and 41 will be re-worded to accurately reflect the Department's intent regarding compliance-related notifications. Specific Condition 27 will be revised to accurately reflect Rule 62-210.700(6), F.A.C.

## FINAL DETERMINATION

JEA

Brandy Branch/Baldwin City  
DEP File No.0310485, PSD-FL-267

13. *Specific Condition 29:* The applicant requested a revision to this condition clarifying the Department's intent concerning initial testing on oil as well as shake-down testing.

RESPONSE: Language similar to that proposed by the applicant will be added for initial testing on oil. However, the condition will not be revised in such a manner to allow routine or repetitive shakedown periods after the initial 100 days of operation.

14. *Specific Condition 30:* The applicant requested a revision to this condition eliminating reference to SCR controls and clarifying the Department's intent concerning 3-hr and 24-hr averaging times for NOx compliance.

RESPONSE: The Department will clarify its intent. However, the Department intends to allow for the possibility of SCR controls to be installed as indicated in prior discussion above.

15. *Specific Condition 31:* The applicant requested a revision to this condition so as to have similar language to other permits regarding the sulfur content of natural gas.

RESPONSE: The Department will modify the language so as to replicate other permits.

16. *Specific Condition 33:* The applicant requested a revision to this condition so as to eliminate the reference to the VOC limit having been determined by BACT.

RESPONSE: The Department will eliminate this reference in this condition.

17. *Specific Condition 40:* The applicant requested a revision to this condition to be consistent with its request in item 4. above.

RESPONSE: The Department will revise this condition so as to provide a means of compliance with the newly worded permit conditions (concerning hours of operation per CT).

18. *Specific Condition 41:* The applicant requested that this condition be revised so as to eliminate the last sentence or (at a minimum) to eliminate the words "and fuel switching".

RESPONSE: The Department will eliminate the words "and fuel switching".

19. *Specific Condition 43:* The applicant requested that this condition be revised so as to be consistent with other similar permitting actions.

RESPONSE: The Department will comply with this request.

20. *Specific Condition 45:* The applicant requested that this condition be revised for clarity so as to indicate when an Acid Rain permit should be applied for.

RESPONSE: The Department will comply with this request.

## CONCLUSION

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



# Department of Environmental Protection

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

David B. Struhs  
Secretary

Jeb Bush  
Governor  
**PERMITTEE:**

Jacksonville Electric Authority  
Brandy Branch Facility  
21 West Church Street  
Jacksonville, Florida 32202-3139

File No.	PSD-FL-267
FID No.	0310485
SIC No.	4911
Expires:	12/31/02

*Authorized Representative:*

Walter P. Bussells, Chief Executive Officer

## PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and three 90-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO<sub>x</sub> (DLN-2.6) combustors and wet injection capability. They are designated by JEA as Combustion Turbine Generators 1, 2 and 3 and by the Department as ARMS Emissions Units 001, 002 and 003.

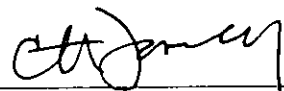
The project will be located approximately 1 mile N.E. of Baldwin City, Duval County. UTM coordinates are: Zone 17; 408.81 km E; 3354.38 km N.

## STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR51.166. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

- Appendix BD                      BACT Determination
- Appendix GC                      Construction Permit General Conditions

  
 for \_\_\_\_\_  
 Howard L. Rhodes, Director  
 Division of Air Resources  
 Management

# AIR CONSTRUCTION PERMIT PSD-FL-267 (0310485-001-AC)

## SECTION I. FACILITY INFORMATION

### FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 90-foot stacks and three fuel oil storage tanks.

Emissions from the new units will be controlled by Dry Low NO<sub>x</sub> (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

### EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSIONS UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank

### REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM<sub>10</sub>), sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO<sub>x</sub>, SO<sub>2</sub>, or VOC; 25/15 TPY of PM/PM<sub>10</sub>; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.



# AIR CONSTRUCTION PERMIT PSD-FL-267 (0310485-001-AC)

## SECTION I. FACILITY INFORMATION

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### PERMIT SCHEDULE

- 08/23/99 Notice of Intent published in The Florida Times-Union
- 08/12/99 Distributed Intent to Issue Permit
- 08/06/99 Application deemed complete
- 05/18/99 Received Application

### RELEVANT DOCUMENTS:

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

- Application received on May 18, 1999
- Department letters dated May 26 and July 21, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- Letter from JEA dated June 21, 1999
- Letter (e-mail) from JEA dated August 4, 1999 and related submittals
- Department's Intent to Issue and Public Notice Package dated August 12, 1999
- Letters (e-mail) from JEA dated August 27 and September 24, 1999
- Letter (facsimile) from EPA dated September 10, 1999
- Letter from Golder Associates Inc. dated September 10, 1999 and regional haze analysis
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

# AIR CONSTRUCTION PERMIT PSD-FL-267 (0310485-001-AC)

## SECTION II. ADMINISTRATIVE REQUIREMENTS

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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) 488-1344. 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 and phone number 904/448-4300; additionally, such documents shall be submitted to RESD, Suite 225, 117 W. Duval St., Jacksonville, Florida 32202 and phone number 904/630-3484.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [62-4.070(4), 62-4.210(2)&(3), 62-210.300(1)(a)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 51.166(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-

# AIR CONSTRUCTION PERMIT PSD-FL-267 (0310485-001-AC)

## SECTION II. ADMINISTRATIVE REQUIREMENTS

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cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166, Rule 62-4.070 F.A.C.]

8. 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 Northeast District office as well as RESD. [Chapter 62-213, F.A.C.]
9. 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.]
10. 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 office as well as RESD by March 1st of each year. [Rule 62-210.370(2), F.A.C.]
11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]
13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to RESD. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
14. Retirement of existing facility: In accordance with JEA's analyses of regional haze in the nearby Class I areas, the Brandy Branch facility may cause or contribute to haze values greater than 5%. In order to mitigate this possibility, JEA will limit the operation of the combustion turbines permitted herein to a maximum of 16 hours per day of oil operation. Additionally, so as to cause a net benefit to the nearby Class I areas, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Colorado Avenue, Jacksonville, Florida upon JEA's application for a Title V permit for the Brandy Branch facility (including certification that the facility is in compliance with applicable requirements and permit conditions). JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered. This shall occur on or before October 31, 2002.

**SECTION III. EMISSION UNITS SPECIFIC CONDITIONS**

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**APPLICABLE STANDARDS AND REGULATIONS:**

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
  - 40CFR60.7, Notification and Recordkeeping
  - 40CFR60.8, Performance Tests
  - 40CFR60.11, Compliance with Standards and Maintenance Requirements
  - 40CFR60.12, Circumvention
  - 40CFR60.13, Monitoring Requirements
  - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with optional evaporative inlet cooling) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]
5. ARMS Emission Units 004-006, Fuel Storage, consisting of three 1 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]
6. All notifications and reports required by the above specific conditions shall be submitted to RESD.

**GENERAL OPERATION REQUIREMENTS**

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

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8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1.623 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,822 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. {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in this permit requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods (including but not limited to) fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the operator to calculate average hourly heat input during the test.} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]
10. 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 RESD 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.]
11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

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- 12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]
- 13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
- 14. [DELETED]
- 15. [DELETED]

**Control Technology**

- 16. Dry Low NO<sub>x</sub> (DLN) combustors shall be installed on each stationary combustion turbine to control NO<sub>x</sub> emissions while firing natural gas. [BACT, Rule 62-4.070, F.A.C.]
- 17. The permittee shall design each stationary combustion turbine, ducting, and stack(s) so as to not preclude installation of SCR equipment and/or oxidation catalyst in the event of a failure to achieve the NO<sub>x</sub> limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22. [Rule 62-4.070, F.A.C.]
- 18. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO<sub>x</sub> emissions. [Design, Rules 62-4.070, 62-212.400, F.A.C.]
- 19. Consistent with best operation and maintenance practices, the DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO<sub>x</sub> emissions and CO emissions. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rules 62-4.070, 62-210.650 F.A.C.]

**EMISSION LIMITS AND STANDARDS**

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO<sub>x</sub> are corrected to 15% O<sub>2</sub> on a dry basis. [Rule 62-212.400, F.A.C.]

Operational Mode (Fuel)	NO <sub>x</sub> (15%O <sub>2</sub> )	CO	VOC***	PM/Visibility (% Opacity)	SO <sub>2</sub> /SAM	Technology and Comments
Natural Gas	10.5 ppm	15** ppm	2 ppm	10	2 grain S per 100 CF	Dry Low NO <sub>x</sub> Burners. Clean fuels, good combustion
Fuel Oil	42 ppm*	20 ppm	3.5 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 750 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

NOTES: \* See Condition 21. \*\* See Condition 22. \*\*\* The VOC limit imposed herein was not determined by BACT.

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#### 21. Nitrogen Oxides (NO<sub>x</sub>) Emissions:

- When NO<sub>x</sub> monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO<sub>x</sub> in the exhaust gas shall not exceed 69.3 lb/hr (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO<sub>x</sub> emissions calculated as NO<sub>2</sub> (at ISO conditions) shall not exceed 10.5 ppm @15% O<sub>2</sub> to be demonstrated by annual stack test nor 9 ppm @15% O<sub>2</sub> to be demonstrated by the initial "new and clean" GE performance stack test. Note: Basis for lb/hr limit is 10.5 ppm @ 15% O<sub>2</sub>, full load. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO<sub>x</sub> in the exhaust gas shall not exceed 42 ppmvd at 15% O<sub>2</sub> on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO<sub>x</sub> emissions calculated as NO<sub>2</sub> (at ISO conditions) shall not exceed 42 ppm @15% O<sub>2</sub> to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- After combusting fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO<sub>x</sub> emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO<sub>x</sub> emission rate based upon this report. [BACT determination]

#### 22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 15 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 48.0 lb/hr (when firing natural gas) and 65.0 lb/hr (when firing fuel oil) as indicated by EPA Method 10. [Rule 62-212.400, F.A.C.]

- Within 18 months after the initial compliance test on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved firing natural gas. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the CO emission rate based upon this report. [BACT determination]

#### 23. Sulfur Dioxide (SO<sub>2</sub>) emissions: SO<sub>2</sub> emissions (at ISO conditions) shall not exceed 1.1 pounds per hour when firing pipeline natural gas and 98.2 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. [Rule 62-212.400, F.A.C.]

#### 24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil. Particulate matter emissions shall not exceed 9.0

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lb/hr (front catch) while firing natural gas and 17.0 lb/hr (front catch) while firing fuel oil as indicated by opacity. [Rule 62-296.320(4)(b), F.A.C.]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 2 ppmvd when firing natural gas and 3.5 ppmvd when firing fuel oil as assured by EPA Methods 18 and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 4.0 lb/hr (when firing natural gas) and 7.5 lb/hr (when firing fuel oil) as indicated by EPA Methods 18 and/or 25A. [Rule 62-212.400, F.A.C.]

#### EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open). 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.
27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify RESD 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, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

#### COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.
29. Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil, in accordance with Specific Condition 28. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after starting the CT) to air pollution control equipment, including low NO<sub>x</sub> burners or SCR. 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 each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.



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- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
  - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
  - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO<sub>x</sub> BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement).
  - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
30. Continuous compliance with the NO<sub>x</sub> emission limits: Continuous compliance with the NO<sub>x</sub> emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN technology while burning gas) or a 3-hr average (SCR technology or while burning oil). For the 24-hr block average (lb/hr) emissions may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO<sub>x</sub> standard. These excess emissions periods shall be reported as required in Conditions 26 and 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO<sub>x</sub> concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]
31. Compliance with the SO<sub>2</sub> and PM/PM<sub>10</sub> emission limits: Notwithstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO<sub>2</sub> and PM<sub>10</sub>. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO<sub>2</sub> standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-941 or D4294-90 (or equivalent latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

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### SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

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32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO<sub>x</sub> test, as required. The initial NO<sub>x</sub> and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO<sub>x</sub> required pursuant to 40 CFR 75 (required for gas only).
33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.
34. 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. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.
35. Test Notification: The DEP's Northeast District office and RESD shall be notified, in writing, at least 30 days prior to the initial performance tests and RESD notified at least 15 days before annual compliance test(s). [40 CFR 60.11]
36. Special Compliance Tests: The DEP or RESD 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.
37. Test Results: Compliance test results shall be submitted to RESD no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.]

### NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by JEA 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 and RESD representatives upon request.
39. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition 37. above. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to

**SECTION III. EMISSION UNITS SPECIFIC CONDITIONS**

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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.

40. Special Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to fuel usage:
- (1) Hours of operation for each combustion turbine by fuel type shall be submitted with the Annual Operation Report (AOR) for the prior year.
  - (2) Hours of operation for each combustion turbine shall kept for each consecutive 12-month period by fuel type.
  - (3) Daily hours of fuel oil operation shall be kept for each combustion turbine during any day in which fuel oil is fired.

**MONITORING REQUIREMENTS**

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each (CT) unit. Periods when NO<sub>x</sub> emissions are above the standards as listed in Specific Condition No 21, shall be reported to RESD pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards listed in Specific Condition No. 21 except as noted in Specific Condition No. 30. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]
42. CEMS in lieu of Water to Fuel Ratio: The NO<sub>x</sub> CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO<sub>x</sub> CEMS. Upon request from DEP, the CEMS emission rates for NO<sub>x</sub> shall be corrected to ISO conditions to demonstrate compliance with the NO<sub>x</sub> standard established in 40 CFR 60.332.
43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Northeast District Office as well as RESD no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

## AIR CONSTRUCTION PERMIT PSD-FL-267 (0310485-001-AC)

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44. 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 or superior grade fuel oil received at the Brandy Branch Power Plant, 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).
45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):
- The permittee shall apply for an Acid Rain permit in compliance with the deadlines specified in 40 CFR 72.30.
  - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
  - Each unit shall be monitored for SO<sub>2</sub> emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
  - JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.
46. Determination of Process Variables:
- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
  - Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

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**JEA Brandy Branch Facility**  
**PSD-FL-267 and 0310485-001-AC**  
**Duval County, Florida**

**BACKGROUND**

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to install three nominal 170 megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Brandy Branch Facility near Baldwin City, Duval County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM<sub>10</sub>), carbon monoxide (CO), nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and sulfuric acid mist (SAM). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 90-foot stacks. JEA proposes to operate these units up to 4000 hours on natural gas and 800 hours on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated August 11, 1999, accompanying the Department's Intent to Issue.

**DATE OF RECEIPT OF A BACT APPLICATION:**

The application was received on May 18, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch.

**REVIEW GROUP MEMBERS:**

Michael P. Halpin, P.E. and A. A. Linero, P.E.

**BACT DETERMINATION REQUESTED BY THE APPLICANT:**

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO <sub>x</sub> Combustors Water Injection (Oil)	12 ppmvd @ 15% O <sub>2</sub> (gas) 42 ppmvd @ 15% O <sub>2</sub> (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (800 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	15 ppm (gas, baseload) 20 ppm (oil baseload)
Sulfur Dioxide	As Above	0.05% S in fuel oil
Sulfuric Acid Mist	As Above	0.05% S in fuel oil

According to the application, the maximum emissions from the facility will be approximately 858 tons per year (TPY) of NO<sub>x</sub>, 366 TPY of CO, 75 TPY of PM/PM<sub>10</sub>, 124 TPY of SO<sub>2</sub>, 15 TPY of SAM, and 21 TPY of VOC.

**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

**BACT DETERMINATION PROCEDURE:**

In accordance with Chapter 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

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

**STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:**

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO<sub>x</sub> @ 15% O<sub>2</sub> (assuming 25 percent efficiency) and 150 ppmvd SO<sub>2</sub> @ 15% O<sub>2</sub> (or <0.8% sulfur in fuel). The BACT proposed by JEA is within the NSPS limit, which allows NO<sub>x</sub> emissions, over 110 ppmvd for the high efficiency units to be purchased for the Brandy Branch Facility.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

**DETERMINATIONS BY EPA AND STATES:**

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed JEA Brandy Branch project is included to facilitate comparison.

**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

Project Location	Power Output and Duty	NO <sub>x</sub> Limit ppmvd @ 15% O <sub>2</sub> and Fuel	Technology	Comments
Lakeland, FL	250 MW SC CON	9/9 - NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO <sub>x</sub> limit on gas Issued 7/98. 250 hrs on oil.
Oleander Cocoa, FL	850 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99. 1000 hrs on oil
JEA Brandy, FL	510 MW SC INT	12 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 5/99. 800 hrs on oil
JEA Kennedy, FL	170 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	170 MW GE MS7241FA CT Issued 2/99. Not PSD/BACT
TEC Polk Power, FL	330 MW SC INT	10.5 - NG 42 - No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Application 2/99. 876 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 - NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 - NG (by 2002) 42 - No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO <sub>x</sub> limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 - NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
SEI Neenah, WI	330 MW SC INT	15/12 - NG 42 - No. 2 FO	DLN WI	2x165 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 8760/699 hrs gas/oil
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous      DLN = Dry Low NO<sub>x</sub> Combustion      FO = Fuel Oil      GE = General Electric  
 SC = Simple Cycle      SCR = Selective Catalytic Reduction      NG = Natural Gas      WH = Westinghouse  
 INT = Intermittent      HSCR = Hot SCR      WI = Water or Steam Injection      ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O <sub>2</sub>	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Oleander Cocoa, FL	12 - NG 20 - FO	3 - NG 6 - FO	10% Opacity	Clean Fuels Good Combustion
JEA Brandy, FL	15 - NG 20/26 (full/part load) - FO	1.4 - NG 1.4 - FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
JEA Kennedy, FL	15 - NG 20 - FO	1.4 - NG 3.5 - FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 - NG 7 - FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? - NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? - NG ? - FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr - NG 8 lb/hr - FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load - NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr - NG 44 lb/hr - FO	Clean Fuels Good Combustion
SEI Neenah, WI	12@>50% load - NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr - NG 41 lb/hr - FO	Clean Fuels Good Combustion
PREPA, PR	9 - FO @15% O <sub>2</sub>	11 - FO @15% O <sub>2</sub>	0.0171 gr/dscf	Clean Fuels Good Combustion

JEA Brandy Branch Facility - Units 001 - 006  
 Three 170 MW Simple Cycle Combustion Turbines

Permit No. PSD -FL-267  
 Facility I.D. No. 0310485

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**OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:**

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

- Comments from EPA dated September 10, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO<sub>x</sub> Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Brandy Branch Station Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combustion Turbine Startup Curves
- JEA Website – [www.jea.com](http://www.jea.com)
- Goal Line Environmental Technologies Website – [www.glet.com](http://www.glet.com)
- Catalytica Website – [www.catalytica-inc.com](http://www.catalytica-inc.com)

**REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:**

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO<sub>x</sub> Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

**Nitrogen Oxides Formation**

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO<sub>x</sub> forms in the high temperature area of the gas turbine combustor. Thermal NO<sub>x</sub> increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO<sub>x</sub> formation. Prompt NO<sub>x</sub> is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO<sub>x</sub> is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO<sub>x</sub> control by lean combustion.

Fuel NO<sub>x</sub> is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the JEA project because these units will not be continuously operated, but rather will be “peakers”. Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 800 hours per year (per CT). Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O<sub>2</sub>). The Department



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estimates uncontrolled emissions at approximately 200 ppmvd @15% O<sub>2</sub> for each turbine of the JEA Project. The proposed NO<sub>x</sub> controls will reduce these emissions significantly.

### **NO<sub>x</sub> Control Techniques**

#### Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO<sub>x</sub> formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

#### Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO<sub>x</sub> formation. Lean premixing of fuel and air prior to combustion can further reduce NO<sub>x</sub> emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

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

To further reduce NO<sub>x</sub> emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called “quaternary fuel” is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the JEA project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO<sub>x</sub> limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority’s Kennedy Station.

NO<sub>x</sub> concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO<sub>x</sub> at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the “unburned hydrocarbons” which in turn is mostly non-VOC methane.

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The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO<sub>x</sub> and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the JEA project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO<sub>x</sub> formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO<sub>x</sub> emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO<sub>x</sub> formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower NO<sub>x</sub> emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

#### Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO<sub>x</sub> control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO<sub>x</sub> emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO<sub>x</sub> in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1125 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

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

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Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO<sub>x</sub> have been specified using SCR on combined cycle F Class projects throughout the country.

Selective Non-Catalytic Combustion

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

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at least two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called SCONOX™ and is a catalytic technology that achieves NO<sub>x</sub> control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.<sup>1</sup> California regulators and industry sources have stated that the first 250 MW block to install SCONOX™ will be at U.S. Generating's La Paloma Plant near Bakersfield.<sup>2</sup> The overall project includes several more 250 MW blocks with SCR for control.<sup>3</sup> USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOX™ system

SCONOX™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO<sub>x</sub> reduction. Advantages of the SCONOX™ process include in addition to the reduction of NO<sub>x</sub>, the elimination of ammonia and the control of some CO emissions. SCONOX™ has not been applied on any major sources in ozone attainment areas.

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In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO<sub>x</sub> emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO<sub>x</sub> combustion) followed by flameless catalytic combustion to further attenuate NO<sub>x</sub> formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

**REVIEW OF SULFUR DIOXIDE (SO<sub>2</sub>) AND SULFURIC ACID MIST (SAM)**

SO<sub>2</sub> control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines

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contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO<sub>2</sub>.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil for up to 800 hours per CT as well as pipeline natural gas. The applicant estimated total emissions for the project at 124 TPY of SO<sub>2</sub> and 15 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100ft<sup>3</sup>). This value is well below the "default" maximum value of 20 gr. S/100 ft<sup>3</sup>, but high enough to require a BACT determination.

**REVIEW OF PARTICULATE MATTER (PM/PM<sub>10</sub>) CONTROL TECHNOLOGIES:**

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO<sub>x</sub> controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM<sub>10</sub>).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 800 hours per year making any conceivable add-on control technique for PM/PM<sub>10</sub> either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM<sub>10</sub> is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM<sub>10</sub> for the project are expected to be approximately 75 tons per year.

**REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES**

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

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.<sup>4</sup>

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations typically achieve emissions between 10 and 25 ppm at full load while firing gas. The values of 15 and 20 ppm for gas and oil respectively at baseload proposed in JEA's original application are within the range of recent determinations for simple cycle CO BACT determinations. By comparison, values of 12 and 20 ppm for gas and oil respectively (at baseload) were proposed for

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the Oleander's project using identical equipment. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

**REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES**

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by JEA for this project are 1.4 ppm for both gas and oil firing at baseload. According to GE, however, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.<sup>5</sup> By comparison, limits of 3 and 6 ppm were proposed for gas and oil firing respectively in the Oleander application. The limits proposed by JEA are sufficiently low to exempt the Brandy Branch project from BACT for VOC.

**BACKGROUND ON PROPOSED GAS TURBINE**

JEA plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

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

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.<sup>7</sup> The units were equipped with DLN-2 combustors with a permitted NO<sub>x</sub> limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO<sub>x</sub>, 0-3 ppm of CO, and 0-0.17 ppm of VOC.<sup>8</sup> The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.<sup>9</sup> Although permitted emissions are 12 ppmvd of NO<sub>x</sub>, the City obtained a performance guarantee from GE of 9 ppmvd.<sup>10</sup> FPL also obtained a guarantee and permit limit of 9 ppmvd NO<sub>x</sub> for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.<sup>11</sup> The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO<sub>x</sub> limit for a GE 7241 turbine with DLN-2.6 burners.<sup>12</sup>

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities). These three draft permits also include NO<sub>x</sub> limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO<sub>x</sub> control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.<sup>13</sup> In its recent permits, Florida has included separate and lower limits in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

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

The 12 ppmvd NO<sub>x</sub> limit on natural gas proposed by JEA is a fairly stringent BACT determination for simple cycle F Class, though it is becoming less so. The company has obtained a guarantee from GE to achieve 9 ppmvd, which is for a performance test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation as specified in the GE protocols.

With the frequent start-ups and shutdowns of the unit, JEA is concerned about the ability to maintain the low (9 ppmvd) NO<sub>x</sub> values for long periods of time following the performance tests. Presumably, this concern would be lessened should these units be converted to a more continuous duty (i.e. combined cycle). Although the Department is not fully aware of the details of the GE guarantee for Oleander (proposed 9 ppmvd on a simple cycle unit), the Department is aware from discussions with other applicants that a continuing guarantee is available at a substantial cost.<sup>17</sup>

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO<sub>x</sub> techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.<sup>18</sup>

**DEPARTMENT BACT DETERMINATION**

Following are the BACT limits determined for the JEA project assuming full load. Values for NO<sub>x</sub> are corrected to 15% O<sub>2</sub> on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 25.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM <sub>10</sub>	Pipeline Natural Gas Good Combustion	10 Percent Opacity 9 lb/hr – Gas 17 lb/hr – Fuel Oil
CO	As Above	12* ppm – Gas 20 ppm – Fuel Oil
SO <sub>2</sub> /SAM	As Above	2 grains of sulfur per 100 ft <sup>3</sup> gas 0.05 percent sulfur in fuel oil
NO <sub>x</sub>	Dry Low NO <sub>x</sub> , WI for F.O., limited oil use	10.5 ppmvd – Gas 42* ppmvd – F.O. for 750 of 4750hours

\* See discussion below.

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**RATIONALE FOR DEPARTMENT'S DETERMINATION**

- JEA has agreed to shutdown its Southside facility, also located in Duval County. This will result in a net decrease of regulated pollutants which are emitted.
- General Electric has provided a “clean and new” one-time guarantee of 9 ppmvd NO<sub>x</sub>.
- Typical “continuous” permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 12-15 ppmvd even though GE provides the same “new and clean” guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd NO<sub>x</sub> by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was proposed by Oleander for five GE7 FA units and is reflected in the Department’s recent Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander and Virginia Power while firing natural gas is the lowest known Draft BACT value for an “F” frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department prepared a Draft permit for the TEC Polk Power Station Project adopting TEC’s proposed 10.5 ppmvd limit for two GE 7FA units, but limited the hours of operation on fuel to less than the hours allowed at Oleander. The TEC Draft BACT is being issued concurrently with the Draft BACT for the JEA project.
- JEA’s proposed 12 ppmvd limit for the Brandy Branch Facility while firing natural gas is relatively low for a GE 7FA Class simple cycle, intermittent duty unit.
- The Department however, proposes a BACT limit of 10.5 ppmvd, which is the same as proposed for the TEC project. The Department also proposes to limit oil firing to the same number of hours as TEC (750) and less than the number of hours at Oleander (1000). Considering the applicant’s shutdown of its Southside facility in conjunction with the Department’s BACT limits, net annual NO<sub>x</sub> emissions (TPY) will be approximately zero.
- The Department will still require JEA to meet to meet the “clean and new” limit of 9 ppmvd during initial testing as well as requiring a continuous 9 ppmvd guarantee (or better) in the event that JEA converts the units to continuous duty (i.e. combined cycle).
- The proposed BACT limit of 10.5 ppmvd is about one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO<sub>x</sub> or lower. It also rules out the possibility of SCONOX. XONON is not available for F Class dual fuel projects.
- The simple cycle “F Class” turbines have very high exhaust temperatures of up to 1200 °F. Without additional cooling, this is at the higher limit of the present operational temperature of



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Hot SCR zeolite catalyst (around 1125°F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024°F and burn exclusively #2 oil.

- The levelized costs of NO<sub>x</sub> removal by Hot SCR for the JEA project were estimated by Black & Veatch at \$13,380 per ton assuming 4000 hours of operation on natural gas and a reduction from 12 to 5 ppmvd. The Department estimates that this figure is reduced by including oil operation (up to 750 hours per year) and other criteria, but still exceeds \$7,000 per ton.
- TEC estimated the cost of Hot SCR at \$9,717 per ton of NO<sub>x</sub> removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.
- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle projects (PREPA).
- Although the Department does not have a “bright line” cost-effectiveness figure and does not necessarily adopt the precise cost calculations for the JEA and TEC projects, the values projected by JEA and TEC indicate that Hot SCR is not cost-effective for their respective projects.
- Comments from the National Park Service on the Oleander project suggested that a reduction in the applicant’s proposed NO<sub>x</sub> emissions on oil from 42 ppmvd to 25 ppmvd is possible based on reported oil-fired units listed in the BACT Clearinghouse. GE has advised that it only offers a 42 ppmvd NO<sub>x</sub> guarantee on F Class units when firing oil.
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- It is possible that the NO<sub>x</sub> emissions while firing oil from may be reduced from 42\*ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department’s review to ensure that the lowest reliable NO<sub>x</sub> emission rates while firing oil have been achieved.
- The Department’s overall BACT determination is equivalent to approximately 0.5 lb./MW-hr NO<sub>x</sub> emissions for combined gas and oil operation. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr. FDEP BACT analyses typically target values less than 1.0 lb./MW-hr for simple cycle CT’s and less than 0.5 lb./MW-hr for combined cycle units.
- VOC emissions of 1.4 ppm while firing gas or oil proposed by the applicant clearly reflect BACT and, in fact, exempt the project from a BACT determination for VOC. The Department will set VOC limits at 2 ppm (gas) and 3.5 ppm (oil). These values are still sufficient to maintain VOC emissions to less than 40 tons per year.
- The Department will set CO limits achievable by good combustion at full load as 12\* ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units and are equal to those proposed by the Department for Oleander and TEC project. Due to the applicant’s (higher) guarantee while firing gas of 15 ppm, the specific permit condition will be worded so as to allow for initial 15 ppm operation with a requirement

**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable CO emission rates while firing gas have been achieved.

- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88 percent control efficiency and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of the project by \$1,905,000 with an annualized cost of \$509,000 per year. Levelized costs for CO catalyst control were calculated at \$4,700 per ton. This figure does not appear to be cost-effective for removal of CO.
- BACT for PM<sub>10</sub> was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels for limited hours, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM<sub>10</sub> emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy Center, FPL Fort Myers, and the Southern Company Barry projects.

**Compliance Procedures**

POLLUTANT	COMPLIANCE PROCEDURE
Particulate Matter	Method 9
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO <sub>x</sub> (performance)	Annual Method 20 (can use RATA if at capacity)
NO <sub>x</sub> (24-hr block average)	NO <sub>x</sub> CEMS, O <sub>2</sub> or CO <sub>2</sub> diluent monitor, and flow device as needed
SO <sub>2</sub> and SAM	Custom Fuel Monitoring Schedule

**DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:**

Michael P. Halpin, P.E., Review Engineer, New Source Review Section *MPH* PE  
 A. A. Linero, P.E. Administrator, New Source Review Section *AAL* PE  
 Department of Environmental Protection / Bureau of Air Regulation  
 2600 Blair Stone Road  
 Tallahassee, Florida 32399-2400

Recommended By:

Approved By:

*C. H. Fancy*

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

*Howard I. Rhodes*

for Howard I. Rhodes, Director  
Division of Air Resources Management

10/13/99

Date:

10/13/99

Date:

**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

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**REFERENCES**

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- <sup>1</sup> News Release. Goaline Environmental. Genetics Institute Buys SCONOX Clean Air System. August 20, 1999.
- <sup>2</sup> "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.
- <sup>3</sup> Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.
- <sup>4</sup> Letter from Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee unit 3. December 9, 1998.
- <sup>5</sup> Telecom. Vandervort, C., GE, and Linero, A.A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."
- <sup>6</sup> Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.
- <sup>7</sup> Davis, L.B., GE. "Dry Low NO<sub>x</sub> Combustion Systems for GE Heavy Duty Gas Turbines." 1994.
- <sup>8</sup> Report. Florida Power & Light. "Final Dry Low NO<sub>x</sub> Verification Testing at Martin Combine Cycle Plant." August 7, 1995.
- <sup>9</sup> Florida DEP. PSD Permit, City of Tallahassee Purdom Unit 8. May, 1998.
- <sup>10</sup> City of Tallahassee. PSD/Site Certification Application. April, 1997.
- <sup>11</sup> Florida DEP. Intent to Issue Permit. FPL Fort Myers Repowering Project. September, 1998.
- <sup>12</sup> Florida DEP. Final Permit. Santa Rosa Energy Center. December, 1998.
- <sup>13</sup> State of Alabama. PSD Permit, Alabama Power/Barry Sithe/IPP (GE 7FA).
- <sup>14</sup> Telecom. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program
- <sup>15</sup> Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.
- <sup>16</sup> Telecom. Schorr, M., GE, and Linero, A.A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.
- <sup>17</sup> Telecom. Gianazza, N.B., JEA, and Linero, A.A., Florida DEP. Proposed NO<sub>x</sub> limits at Brandy Branch Project.
- <sup>18</sup> Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."

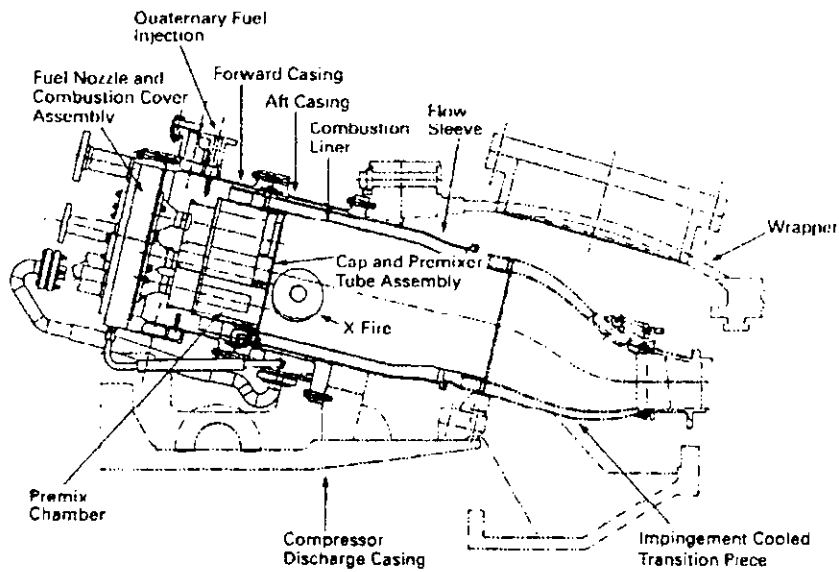
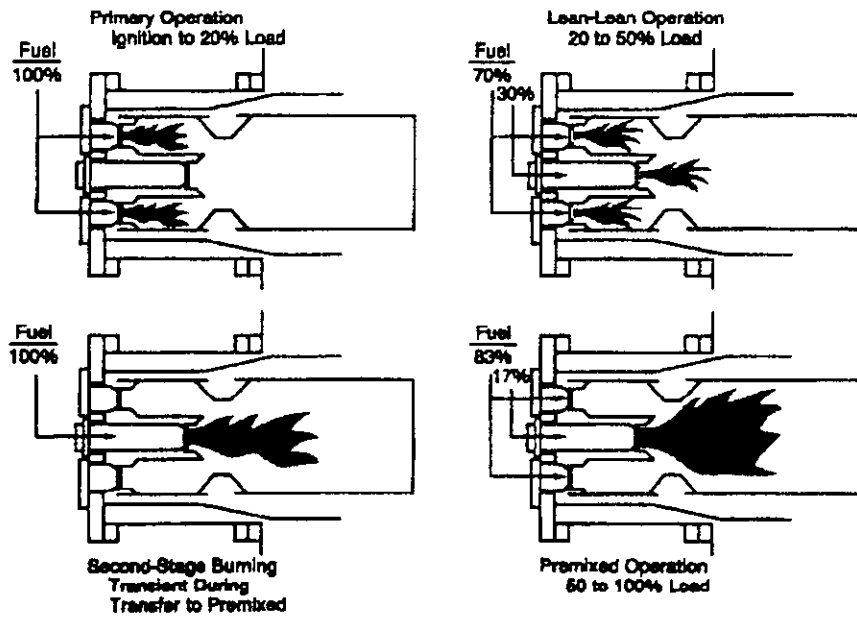
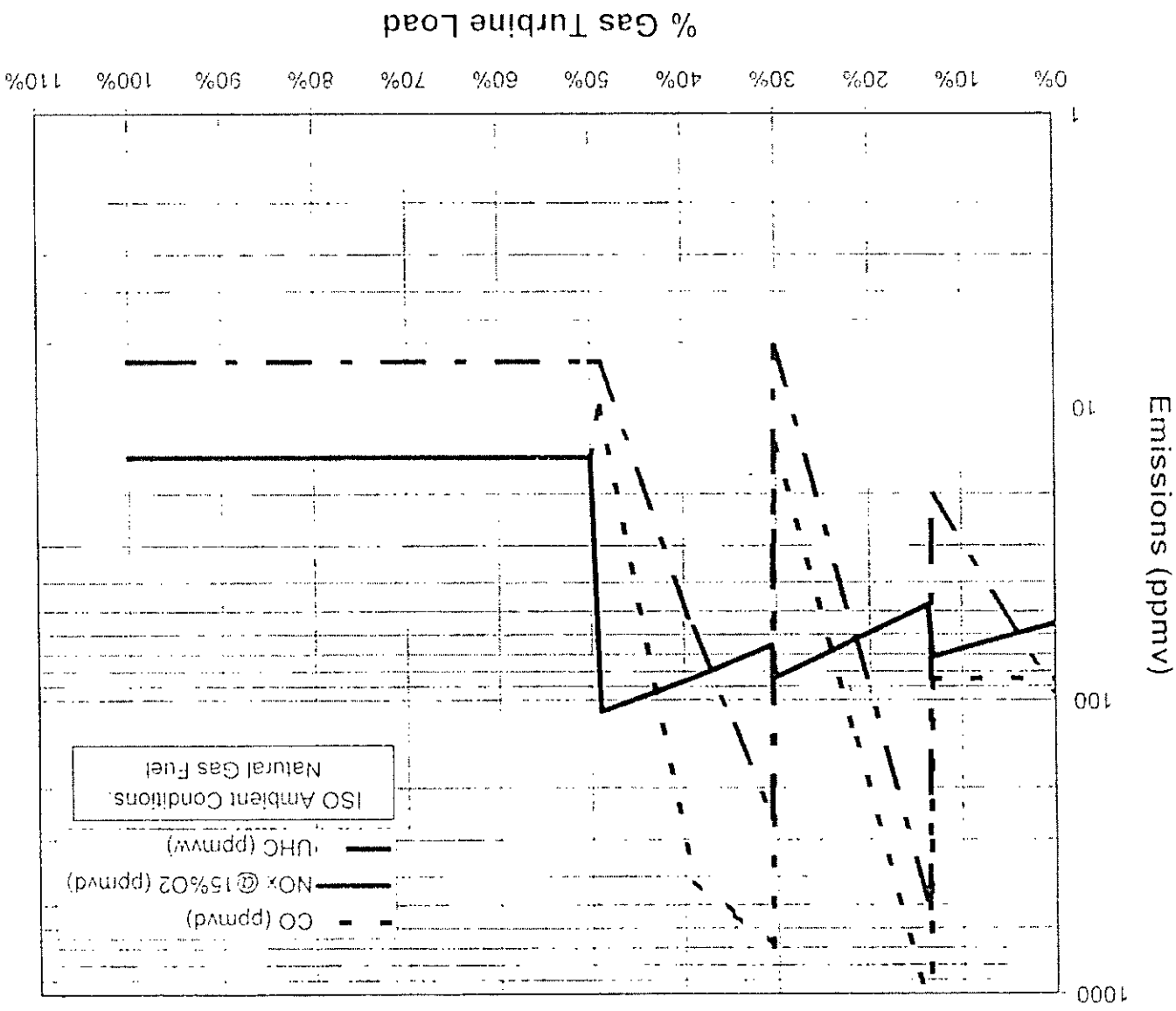


Figure 1 - Dry Low NO<sub>x</sub> Operating Modes - DLN-1

Cross Section of GE DLN-2

Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine (Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NOx)



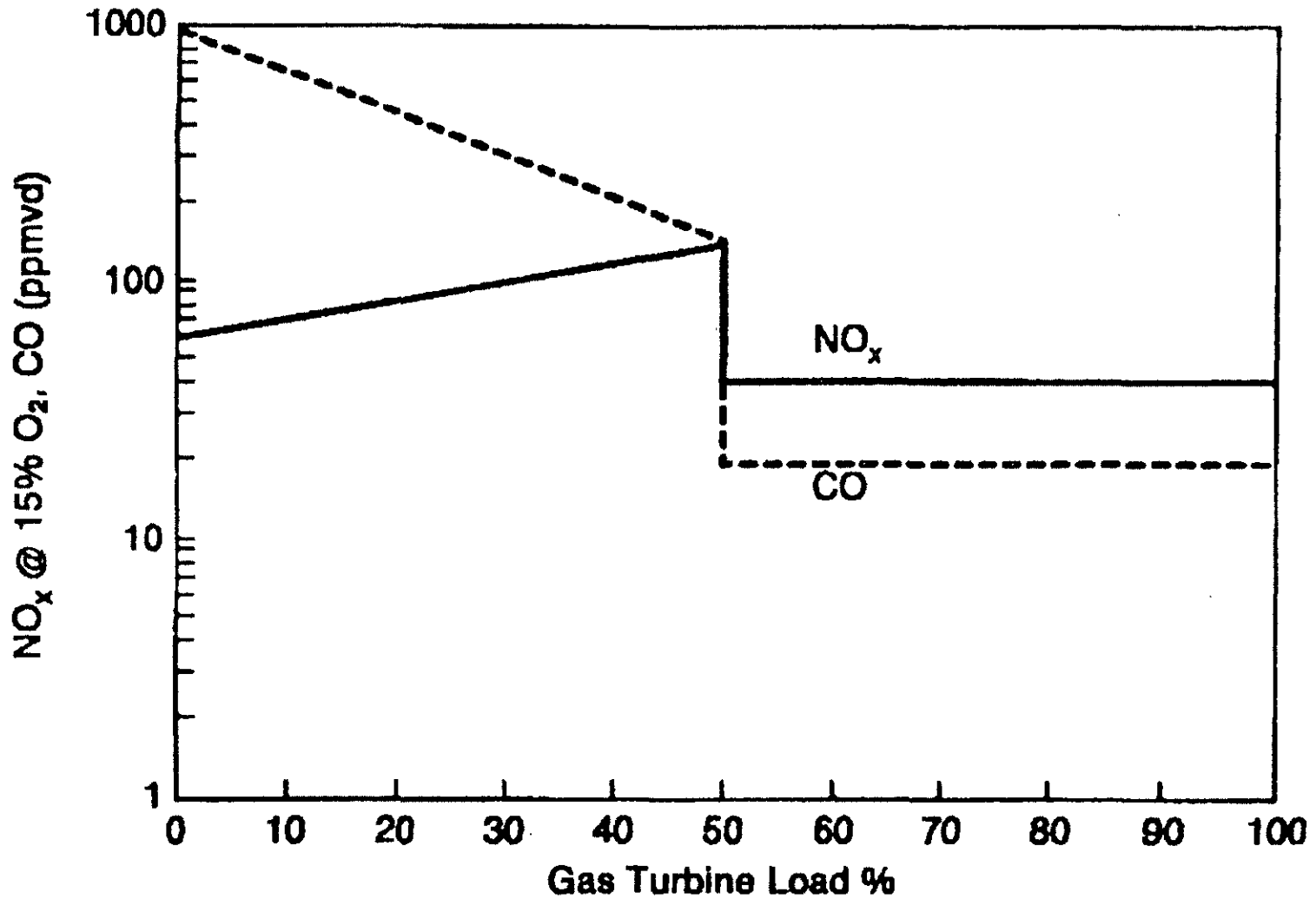


Figure 3 – Emissions Performance for DLN-2 Combustors  
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

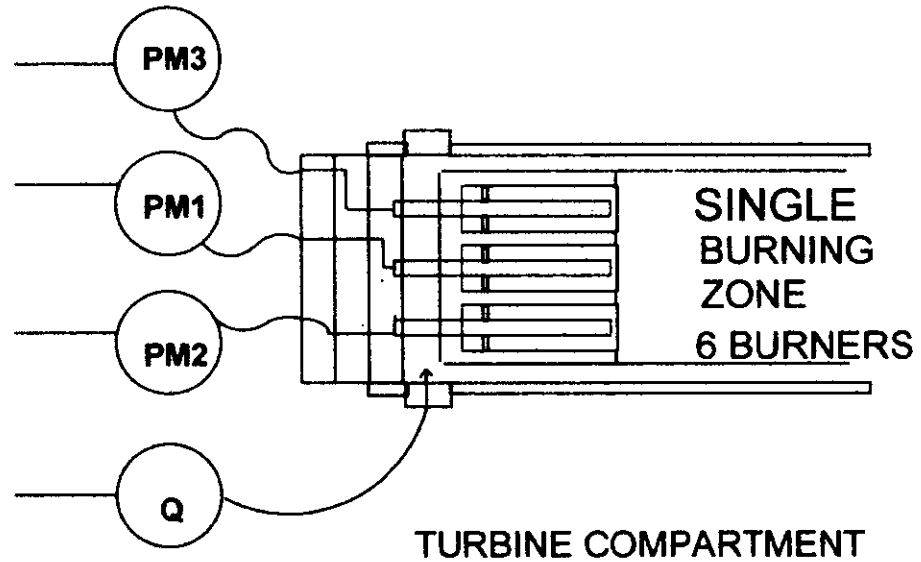
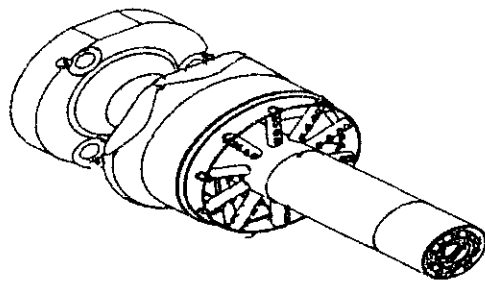
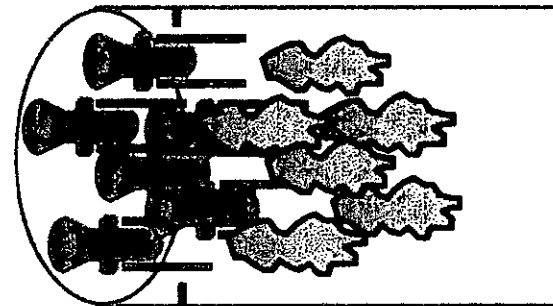
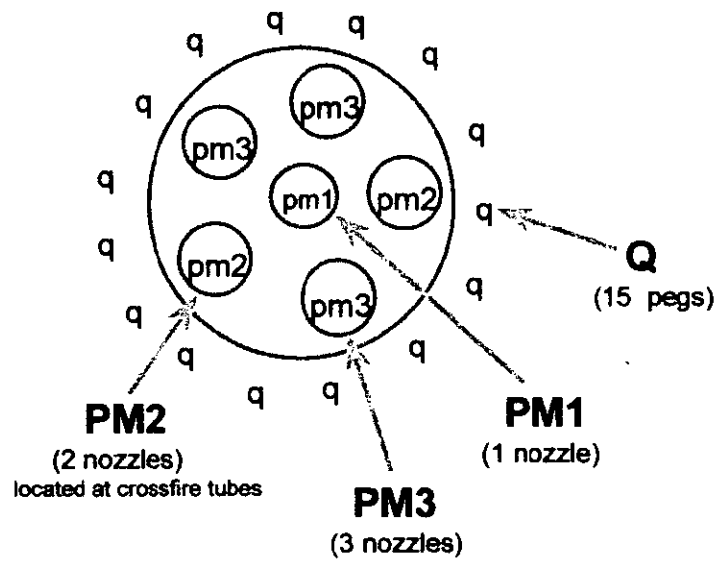


Figure 4 - DLN-2.6 Nozzle and Burner Arrangement

## Gas Turbine - Hot Gas Path Parts

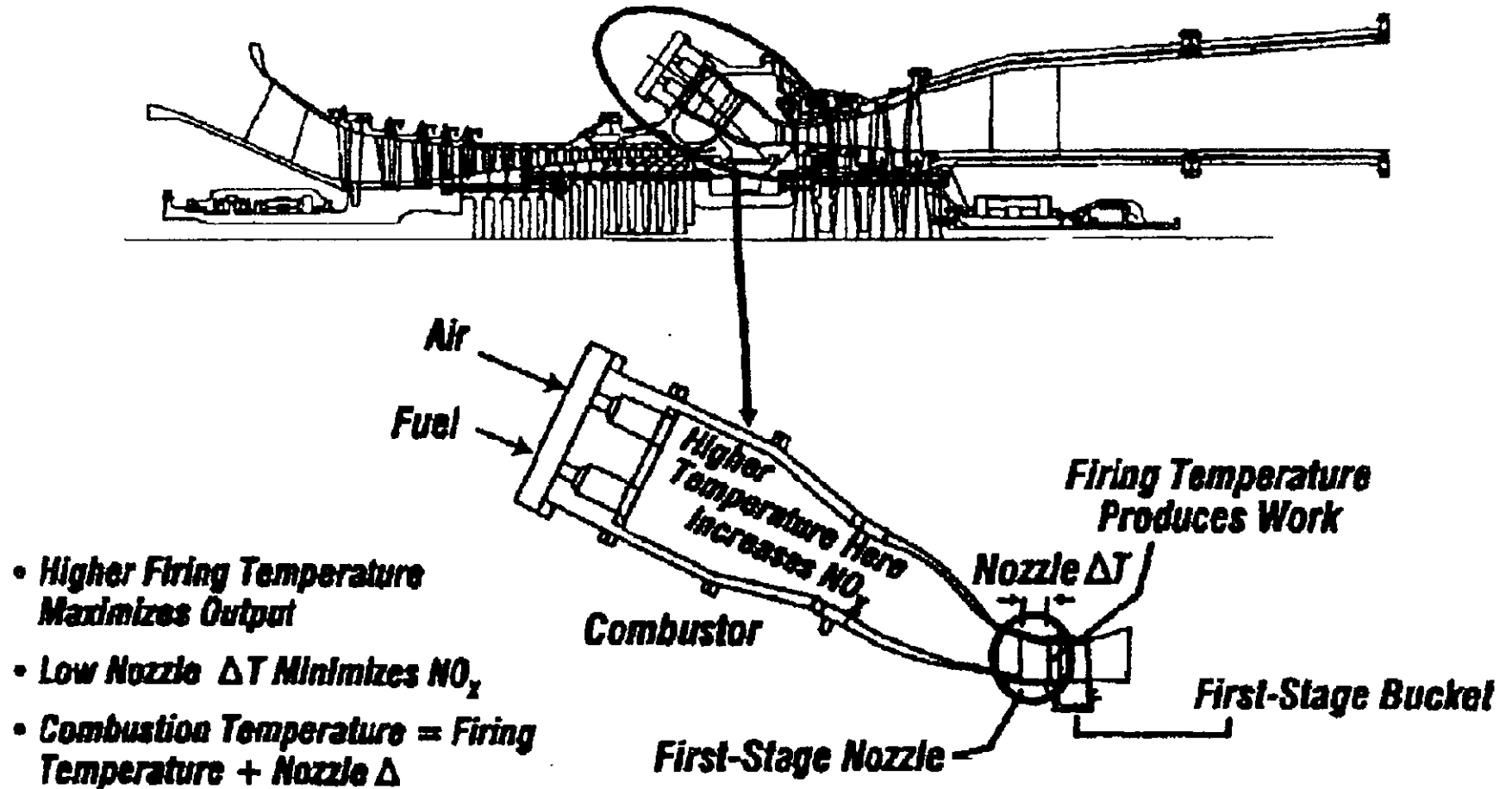


Figure 5 - Relation Between Flame Temperature and Firing Temperature



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

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- G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
- G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
- G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
- G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
- G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
- G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
- G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
- a) Have access to and copy and records that must be kept under the conditions of the permit;
  - b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
  - c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

- G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
- a) A description of and cause of non-compliance; and
  - b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

- G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
- G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
- G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
- G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.
- G.13 This permit also constitutes:
- a) Determination of Best Available Control Technology ( )
  - b) Determination of Prevention of Significant Deterioration ( ); and
  - c) Compliance with New Source Performance Standards (X).
- G.14 The permittee shall comply with the following:
- a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
  - b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
  - c) Records of monitoring information shall include:
    - 1. The date, exact place, and time of sampling or measurements;
    - 2. The person responsible for performing the sampling or measurements;
    - 3. The dates analyses were performed;
    - 4. The person responsible for performing the analyses;
    - 5. The analytical techniques or methods used; and
    - 6. The results of such analyses.
- G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Florida Department of  
Environmental Protection

Memorandum

TO: Howard L. Rhodes

THRU: Clair Fancy  
Al Linero *raf 10/12*

FROM: Mike Halpin *MH*

DATE: October 11, 1999

SUBJECT: JEA Brandy Branch PSD Permit

Attached for approval and signature is an air construction permit for the subject (new) facility. The Public Notice requirements have been met on August 23, 1999 by publishing in the Florida Times-Union. The applicant filed for and received an enlargement of time in which to file a petition for Administrative Proceeding. This expired on October 1, 1999.

Comments were received by the US EPA, US Fish and Wildlife Service as well as the applicant and are addressed within the Final Determination.

I recommend your approval and signature.

Day 90 is 12/3/99.

Attachments

/mph

*Clair - These guys ran CALPUFF and passed  
They reduced fuel oil burning to max of 16 hrs/day  
+ 750 hrs/year  
They made shutdown of Southside a commitment.  
Let's give them their permit promptly!  
Banks AL*