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Jacksonville, Florida 32202-3139

JEA

August 25, 2000

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BUREAU OF AIR REGULATION

ELECTRIC
WATER
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Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Kennedy Generating Station (Title V Permit No. 0310047-001-AV)
Combustion Turbine 7 (Air Construction Permit No. 0310047-002-AC)

0310047-006-AV

Dear Mr. Fancy:

I am enclosing an original and three (3) copies of our application for a permit revision to our Kennedy Generating Station Title V permit to incorporate the above referenced combustion turbine.

If you have any questions with regard to this matter, please do not hesitate to contact me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

Enclosure

cc: S. Pace, P.E., RESD

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2 To (Recipient)

Company name: FL [illegible]t. of Environmental Protection

Attention: Claire M. Fancy, P.E.

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2600 Blair Stone Road
Tallahassee, Florida

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Signature (required): Brian A. English

Date: 08/25/00

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Recipient's Copy

APPLICATION FOR A
TITLE V AIR OPERATION PERMIT REVISION
FOR THE
KENNEDY GENERATING STATION

Submitted by
JEA

Prepared by
Black & Veatch

August 2000
Project No. 98208

Department of
Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: JEA	
2. Site Name: Kennedy Generating Station	
3. Facility Identification Number: 0310047 [ ] Unknown	
4. Facility Location: Street Address or Other Locator: 4215 Talleyrand Avenue City: Jacksonville County: Duval Zip Code: 32206	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: N. Bert Gianazza, PE, Environmental Health & Safety Group
2. Application Contact Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street, Tower 8 City: Jacksonville State: Florida Zip Code: 32202
3. Application Contact Telephone Numbers: Telephone: (904) 665-6247 Fax: (904) 665-7376

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ____________________

[X] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: 0310047-002-AC

Operation permit number to be revised: 0310047-001-AV

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ____________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: ____________________

Reason for revision: ____________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Walter P. Bussells, Managing Director & CEO
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: Florida Zip Code: 32202
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (904) 665-7220 Fax: (904) 665-7366
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [X], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Signature Date 8/24/00

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: Donald Dean Schultz Registration Number: 30304
2.	Professional Engineer Mailing Address: Organization/Firm: Black & Veatch Corporation Street Address: 8400 Ward Parkway City: Kansas City State: Missouri Zip Code: 64114
3.	Professional Engineer Telephone Numbers: Telephone: (913) 458 -2028 Fax: (913) 458 -2934

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [X], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature: D. Schultz Date: 8/14/2000

(Seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
015	One 170 MW Simple Cycle Combustion Turbine Generator – Peaking Unit	N/A	N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $____________________ [**X**] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: JEA has constructed a nominal 170 MW natural gas and No. 2 distillate fuel oil fired simple cycle combustion turbine (SCCT) electrical generating unit at the existing Kennedy Generating Station (KGS) in accordance with Air Construction Permit No. 0310047-002-AC. The SCCT is a General Electric PG7241 FA, and it replaces KGS Unit 10 (ARMS Unit No. 009) which was decommissioned on April 1, 2000.
2. Projected or Actual Date of Commencement of Construction: March 8, 1999
3. Projected Date of Completion of Construction: N/A

Application Comment

None.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17	East (km): 440.065	North (km): 3359.150	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 30/21/52	Longitude (DD/MM/SS): 81/37/25		
3. Governmental Facility Code: 4	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters): None.			

Facility Contact

1. Name and Title of Facility Contact: Ken Davis		
2. Facility Contact Mailing Address: Organization/Firm: JEA Street Address: 4377 Heckscher Drive City: Jacksonville	State: FL	Zip Code: 32206
3. Facility Contact Telephone Numbers: Telephone: (904) 665-6763	Fax: (904) 665-6731	

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): None.	

List of Applicable Regulations

Facility-wide applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.	
Facility-wide applicable regulations specified in Section II of KGS Initial Title V Air Operating Permit (Final Permit No.: 0310047-001-AV) are hereby incorporated by reference.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
CO	A				
NOX	A				
PM	A				
PM10	A				
SO2	A				
VOC	A				
HAPS	A				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: Attachment 1 [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: Attachment 2 [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [ ] Attached, Document ID:________ [ ] Not Applicable [**X**] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [ ] Not Applicable [**X**] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [**X**] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID:________ [**X**] Not Applicable
7. Supplemental Requirements Comment: A waiver is requested for Supplemental Requirement Items 3 and 4, as these items are not altered as the result of this permit application and have previously been supplied with in the last 5 years in the following permit applications: -Air Construction Permit 0310047-002-AC Application of October 30, 1998. -Title V Air Operating Permit 0310047-001-AV Application of June 14, 1996.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:___ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:___ [X] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [**X**] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [**X**] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [**X**] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [X] Not Applicable
14. Compliance Report and Plan: [X] Attached, Document ID:_Attachment 3___[ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [X] Attached, Document ID:_Attachment 4___[ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
One 170 MW Simple Cycle Combustion Turbine Generator – Peaking Unit

4. Emissions Unit Identification Number: [ ] No ID
ID: 015 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	4/30/00	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

None.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Dry Low NOx (DLN) Combustor. Water injection during fuel oil firing. Use of low sulfur fuel oil (0.05 %) and natural gas.	
2. Control Device or Method Code(s): 024, 028	

Emissions Unit Details

1. Package Unit: Simple cycle combustion turbine generator Manufacturer: General Electric	Model Number: PG 7241 FA
2. Generator Nameplate Rating:	170 MW
3. Incinerator Information: N/A Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,623 (@ 59F/60%RH)	mmBtu/hr
2. Maximum Incineration Rate:	N/A	lb/hr	tons/day
3. Maximum Process or Throughput Rate: N/A			
4. Maximum Production Rate: N/A			
5. Requested Maximum Operating Schedule:			
	24 hours/day		7 days/week
	52 weeks/year		4, 050* hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Maximum Heat Input Rate in Field 1 is based on natural gas firing, lower heating value (LHV)

Maximum Heat Input Rate during No.2 fuel oil firing is 1,822 mmBtu/hr (@ 59F/60%RH) LHV

*Maximum hours of operation on natural gas is 4,050 h/yr and 1,260 h/yr on No. 2 fuel oil. Maximum allowable operating hours (MAXHROP) in any 12 month period are calculated pursuant to the following formula:

MAXHROP = 4050-3.215*ACTHROPFO

Where ACTHROPFO = Actual hours of operation on fuel oil.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A – General Provisions	Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.
40 CFR 60, Subpart GG – Standards of Performance for Stationary Gas Turbines	
40 CFR 72, Permits Regulation	
40 CFR 73, Sulfur Dioxide Allowance System	
40 CFR 75, Continuous Emission Monitoring	
62-204.800(7)(b), Federal Regulations Adopted by Reference – Standards of Performance for New Stationary Sources	
62-296.320, General Pollutant Emission Standards	
62-297.520, Station Sources – Emissions Monitoring	
Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 376, Odor Control	
Jacksonville Environmental Protection Board (JEPB), Rule 2, Part IX, General Pollutant Emission Limiting Standards – Objectionable Odor Prohibited	
Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 362, Air and Water Pollution	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? ID #7 on Plot Plan in Attachment 2	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): One 90-foot vertical cylindrical exhaust stack.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 90 feet	7. Exit Diameter: 24 feet
8. Exit Temperature: 1116 °F	9. Actual Volumetric Flow Rate: 2,378,000 acfm	10. Water Vapor: N/A %
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates: Zone: 17 East (km): 440,000 North (km): 3,359,100		
14. Emission Point Comment (limit to 200 characters): None.		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Natural Gas Firing		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.59 mmscf/hr	5. Maximum Annual Rate: 6,444 mmscf/yr	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1020
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = $\frac{\text{1623 MMBtu/ hr}}{\text{1020 MMBtu/mmscf}}$ = 1.59 mmscf/hr Maximum Annual Rate = $\frac{\text{4050 hrs/yr x 1623 MMBtu/ hr}}{\text{1020 MMBtu/mmscf}}$ = 6,444 mmscf/yr		

Segment Description and Rate: Segment __2___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 2 Fuel Oil Firing		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 13.64 thousand gallons/hr	5. Maximum Annual Rate: 17,183.53 thousand gal/yr	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 133.6
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = $\frac{\text{1822 MMBtu/ hr}}{\text{133.6 MMBtu/thousand gallons}}$ = 13.64 thousand gallons/hr Maximum Annual Rate = $\frac{\text{1260 hrs/yr x 1822MMBtu/ hr}}{\text{133.6 MMBtu/thousand gallons}}$ = 17,183.53 thousand gallons/yr		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx	**024, 028**		**EL**
CO			**EL**
VOC			**EL**
SO_2			**EL**
PM			**EL**
PM_{10}			**EL**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 318 lb/hour 200 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 318 lb/hr Reference: Condition 17 of Permit 0310047-002-AC	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential Emissions = 318 lb/hr x 1,260 hrs/yr x 1/2000 tons/lb = 200 tons per year (Fuel Oil Firing)	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Restricted to 200 tpy NOx in accordance with permit condition 17.	

Allowable Emissions Allowable Emissions ___1__ of __2____

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 15 ppm (at 15% O_2) for Natural Gas	4. Equivalent Allowable Emissions: 99 lb/hour 200 tons/year
5. Method of Compliance (limit to 60 characters): - Record keeping - hours of operation per fuel type per 12 month period. - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

Allowable Emissions Allowable Emissions ___2___ of __2____

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 42 ppm (at 15% O_2) for Fuel Oil	4. Equivalent Allowable Emissions: 318 lb/hour 200 tons/year
5. Method of Compliance (limit to 60 characters): - Record keeping - hours of operation per fuel type per 12 month period. - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 48 lb/hour 97.2 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Condition 19 of Permit 0310047-002-AC.	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Max NG emission rate = 48 lb/hr (In accordance with permit condition 19.)
Max number of operation hours firing natural gas = 4,050 hours

Potential Emissions = 48 lb/hr x 4,050 hrs/yr x 1/2000 tons/lb = 97.2 tons per year

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO.
1,260 hours/yr of FO (max).

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 15 ppmvd for natural gas	4. Equivalent Allowable Emissions: 48 lb/hour 97.2 tons/year

5. Method of Compliance (limit to 60 characters):
- Record keeping - hours of operation per fuel type per 12 month period.
- Stack testing

6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters):

4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO.
1,260 hours/yr of FO (max).

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 20 ppmvd for fuel oil	4. Equivalent Allowable Emissions: 97 lb/hour 61.1 tons/year
5. Method of Compliance (limit to 60 characters): - Record keeping - hours of operation per fuel type per 12 month period. - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 19 lb/hour 11.97 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Condition 20 of Permit 0310047-002-AC.	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Max FO emission rate = 19 lb/hr (In accordance with permit condition 20.) Max number of operation hours firing natural gas = 1,260 hours Potential Emissions = 19 lb/hr x 1,260 hrs/yr x 1/2000 tons/lb = 11.97 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

Allowable Emissions Allowable Emissions ____1__ of ____2__

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1.4 ppmvd for natural gas	4. Equivalent Allowable Emissions: 2.9 lb/hour 5.87 tons/year
5. Method of Compliance (limit to 60 characters): - Record keeping - hours of operation per fuel type per 12 month period. - Stack testing	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

Allowable Emissions Allowable Emissions ____2__ of ___2___

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.5 ppmvd for fuel oil	4. Equivalent Allowable Emissions: 19 lb/hour 11.97 tons/year
5. Method of Compliance (limit to 60 characters): Record keeping - hours of operation per fuel type per 12 month period.	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 98 lb/hour 61.74 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Condition 21 of Permit 0310047-002-AC.	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Max FO emission rate = 98 lb/hr (In accordance with permit condition 21.)
Max number of operation hours firing natural gas = 1,260 hours

Potential Emissions = 98 lb/hr x 1,260 hrs/yr x 1/2000 tons/lb = 61.74 tons per year

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO.
1,260 hours/yr of FO (max).

Allowable Emissions Allowable Emissions __1__ of __2_

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: <2gr/100scf (NG)	4. Equivalent Allowable Emissions: 9.7 lb/hour 19.64 tons/year

5. Method of Compliance (limit to 60 characters):
- Record keeping - hours of operation per fuel type per 12 month period.
- Fuel monitoring schedule.

6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters):

4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO.
1,260 hours/yr of FO (max).

Allowable Emissions Allowable Emissions ___2__ of __2____

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.05% (FO)	4. Equivalent Allowable Emissions: 98 lb/hour 61.74 tons/year tons/year
5. Method of Compliance (limit to 60 characters): - Record keeping - hours of operation per fuel type per 12 month period. - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 17 lb/hour 10.71 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Condition 18 of Permit 0310047-002-AC.	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Max FO emission rate = 17 lb/hr (In accordance with permit condition 18.) Max number of operation hours firing natural gas = 1,260 hours Potential Emissions = 17 lb/hr x 1,260 hrs/yr x 1/2000 tons/lb = 10.71 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): 4,050 hours of operation on NG (max) - 3.215 times the hours on 0.05% S (max) FO. 1,260 hours/yr of FO (max).	

Allowable Emissions Allowable Emissions __1__ of __1_

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: 17 lb/hour 10.71 tons/year
5. Method of Compliance (limit to 60 characters): - Record keeping - hours of operation per fuel type per 12 month period. - Fuel monitoring schedule.	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): The applicant can assume a 10% opacity limit for fuel oil firing in lieu of the 17 lb/hr PM limit during fuel oil firing. (In accordance with permit condition 18.)	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation __1____ of __2____

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: 10 % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: - stack testing (EPA method 9)	
5. Visible Emissions Comment (limit to 200 characters): The applicant can request a 10% opacity limit for fuel oil firing in lieu of the 20% opacity limit in conjunction with a 17 lb/hr PM limit during fuel oil firing. (In accordance with air construction permit condition 18.)	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation __2____ of __2____

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: 20 % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: - stack testing (EPA method 9)	
5. Visible Emissions Comment (limit to 200 characters): 20% opacity limit in conjunction with a 17 lb/hr PM limit during fuel oil firing. (In accordance with air construction permit condition 18.)	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor __1__ of _1____

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: TECO Model Number: Model 142C	Serial Number: 42CNL-66199-351
5. Installation Date: July 31, 2000	6. Performance Specification Test Date: August 8, 2000
7. Continuous Monitor Comment (limit to 200 characters): Continuous compliance with the NOX emissions limits will be demonstrated in accordance with permit condition 27 of the air construction permit.	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Attachment 5 [ ] Not Applicable [] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment 6 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment 7 DEP File No 0310047-002-AC ________
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment 8
5. Compliance Test Report [ ] Attached, Document ID:________ [X] Previously submitted, Date: Sent to Mr. Wayne Tutt (QEP) on July 18, 2000. [ ] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: Attachment 9 [] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [X] Attached, Document ID: Attachment 10 [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: Attachment 11 [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

List of Attachments

Attachment 1: *Area Map*

Attachment 2: *Facility Plot Plan*

Attachment 3: *Compliance Report*

Attachment 4: *Compliance Certification*

Attachment 5: *Process Flow Diagram*

Attachment 6: *Fuel Analysis or Specification*

Attachment 7: *Detailed Description of Control Equipment*

Attachment 8: *Description of Stack Sampling Facilities*

Attachment 9: *Procedures for Startup and Shutdown*

Attachment 10: *Alternative Methods of Operation*

Attachment 11: *Acid Rain Part Application*

Attachment 1

II. Facility Information

C. Facility Supplemental Information

1. Area Map

0310047-006 ①

①

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

ARLINGTON QUADRANGLE
FLORIDA–DUVAL CO
7.5 MINUTE SERIES (TOPOGRAPHIC)

Mapped, edited, and published by the Geological Survey

Control by USGS, NOS/NOAA, and Florida Geodetic Survey

Planimetry compiled from NOS charts 1933. Topography from planetable surveys 1948. Revised by photogrammetric methods from aerial photographs taken 1963. Field checked 1963

Selected hydrographic data compiled from NOS chart 577 (1963)
This information is not intended for navigational purposes

Polyconic projection. 10,000-foot grid ticks based on Florida coordinate system, east zone. 1000-meter Universal Transverse Mercator grid ticks, zone 17, shown in blue. 1927 North American Datum. To place on the predicted North American Datum 1983 move the projection lines 22 meters south and 17 meters west as shown by dashed corner ticks

Fine red dashed lines indicate selected fence and field lines where generally visible on aerial photographs. This information is unchecked

Red tint indicates areas in which only landmark buildings are shown

There may be private inholdings within the boundaries of the National or State reservations shown on this map

UTM GRID AND 1981 MAGNETIC NORTH DECLINATION AT CENTER OF SHEET

Revisions shown in purple and woodland compiled from aerial photographs taken 1977 and other sources. This information not field checked. Map edited 1981

Purple tint indicates extension of urban areas

SCALE 1:24 000

CONTOUR INTERVAL 10 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929

DEPTH CURVES AND SOUNDINGS IN FEET—DATUM IS MEAN LOW WATER
THE RELATIONSHIP BETWEEN THE TWO DATUMS IS VARIABLE
SHORELINE SHOWN REPRESENTS THE APPROXIMATE LINE OF MEAN HIGH WATER
THE MEAN RANGE OF TIDE IS APPROXIMATELY 2 FEET

THIS MAP COMPLIES WITH NATIONAL MAP ACCURACY STANDARDS
FOR SALE BY U. S. GEOLOGICAL SURVEY, RESTON, VIRGINIA 22092
A FOLDER DESCRIBING TOPOGRAPHIC MAPS AND SYMBOLS IS AVAILABLE ON REQUEST

FLORIDA
QUADRANGLE LOCATION

ROAD CLASSIFICATION

Heavy-duty — Light-duty
Medium-duty — Unimproved dirt
Interstate Route — U. S. Route — State Route

ARLINGTON, FLA
N3015—W8130/7.5
1963
PHOTOREVISED 1981
DMA 4844 I SE–SERIES V847

Attachment 2

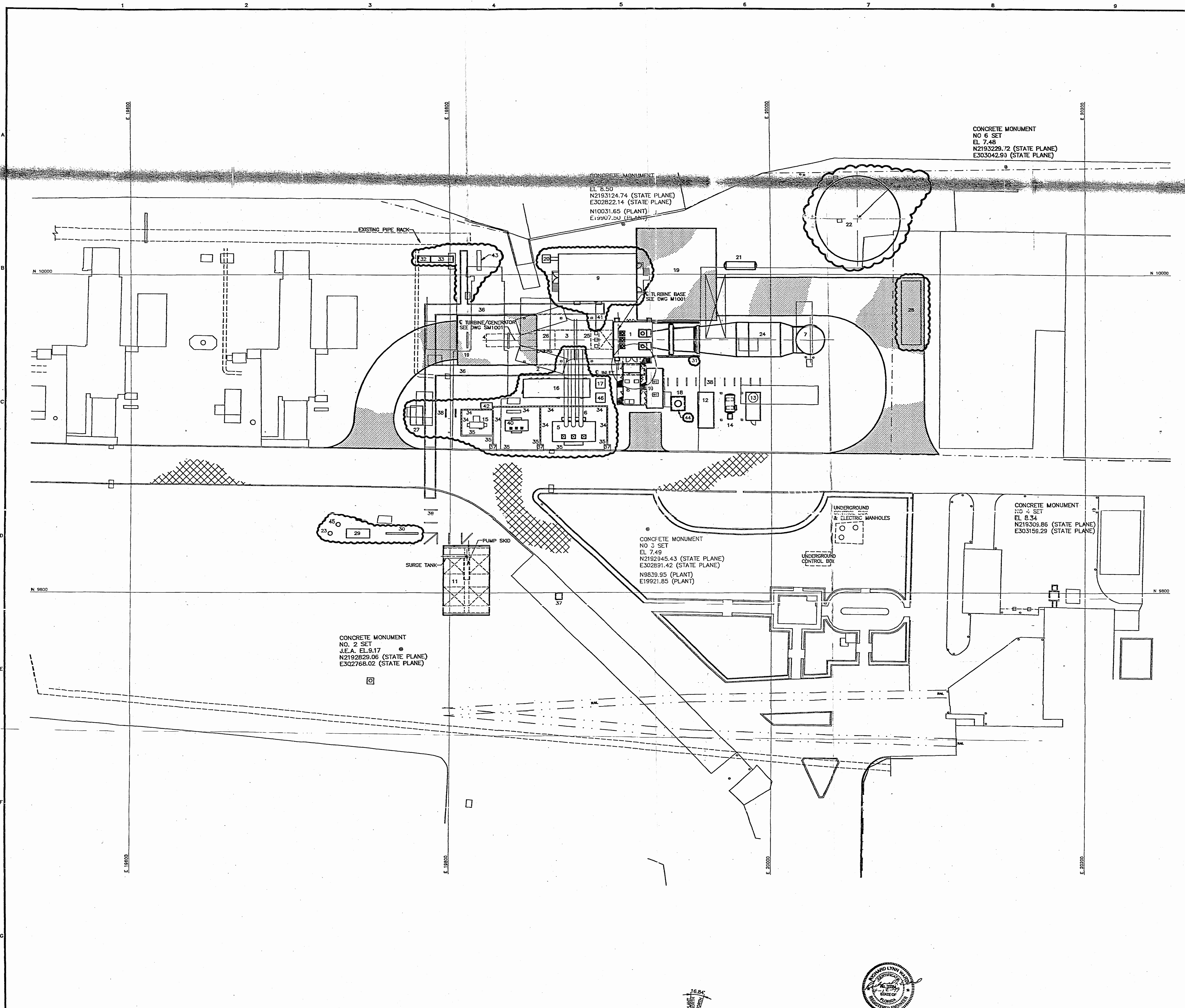
II. Facility Information

C. Facility Supplemental Information

2. Plot Plan

03100047-006 (2)

BEST AVAILABLE COPY



FACILITY LEGEND

1. COMBUSTION TURBINE
2. COMBUSTION TURBINE INLET AIR FILTER
3. COMBUSTION TURBINE GENERATOR
4. GENERATOR ROTOR REMOVAL
5. GENERATOR STEPUP TRANSFORMER
6. ISOLATED PHASE BUS DUCT
7. COMBUSTION TURBINE EXHAUST STACK
8. COMBUSTION TURBINE ACCESSORY MODULE
9. PACKAGED ELECTRICAL/ELECTRONIC CONTROL CENTER
10. LIQUID FUEL/ATOMIZING AIR MODULE
11. C T COOLING WATER SKID
12. C T WATER INJECTION SKID
13. C T WATER WASH SKID
14. C T CO2 FIRE PROTECTION SKID
15. C T ISOLATION AND EXCITATION TRANSFORMER
16. LCI/EXCITATION COMPARTMENT
17. DC LINK REACTOR
18. FALSE START DRAIN TANK
19. COMBUSTION TURBINE MAINTENANCE PAD
20. 1.5MVA TRANFORMER
21. COMPRESSOR DRAIN TANK
22. DEMINERALIZED WATER STORAGE TANK
23. FUEL GAS SCRUBBER
24. EXHAUST DUCT SILENCER
25. GENERATOR TERMINAL ENCLOSURE
26. GENERATOR COMPARTMENT
27. FIRE WATER VALVE STATION
28. PORTABLE DEMINERALIZER
29. FUEL GAS FILTERS
30. FUEL GAS METER
31. ACOUSTIC WALL
32. HYDROGEN STORAGE BOTTLE RACK
33. CO2 STORAGE BOTTLE RACK
34. FIRE WALL
35. 6" HIGH CURB
36. PIPE TRENCH
37. TAKE-OFF TOWER
38. SLEEPER PIPE RACK
39. PIPE TRENCH
40. STARTUP/SERVICE TRANSFORMER T17
41. MONORAIL
42. AIR PROCESSING SKID
43. FUEL OIL MANAGEMENT SPOOL PIECE
44. FALSE START DRAIN TANK CONTAINMENT PIT
45. FUEL GAS SCRUBBER DRAIN TANK
46. AC LINK REACTOR

LEGEND

ASPHALT PAVING
CONCRETE
NEW STRUCTURES
EXISTING STRUCTURES

SCALE: 1"=20'

APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY
1	04-12-99	GENERAL REVISIONS	SKW
0	03-19-99	APPROVED FOR CONSTRUCTION	SKW

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED RICHARD L. WARD
DATE 03-19-99 REG NO. 33384

RICHARD LYNN WARD CERTIFICATE No. 33384 STATE OF FLORIDA REGISTERED ENGINEER 4-12-99

BLACK & VEATCH | JEA Building Community
ENGINEER SKW | DRAWN JWS
CHECKED MJS | DATE 03-19-99

JEA-KENNEDY GENERATING STATION
COMBUSTION TURBINE NO. 7
SITE ARRANGEMENT

PROJECT 29686-7MA | DRAWING NUMBER -S1002 | REV 1
CODE
AREA

022250UMP A1AS008 E1 04/12/99 13:53:12 ACAD 14.01h (Hardware Lock) 1=20

Attachment 3

II. Facility Information
C. Facility Supplemental Information
14. Compliance Report

The new simple cycle combustion turbine generator (E/V 015) is operating in compliance with Air Construction Permit 0310047-002-AC. The unit's initial emission stack tests have been completed and the results submitted to the Jacksonville Regulatory and Environmental Services Department (RESD) and DEP's Northeast District Offices.

Attachment 4

II. Facility Information

C. Facility Supplemental Information

15. Compliance Certification

Compliance Certification

"I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete."

Signature

Date 8/24/00

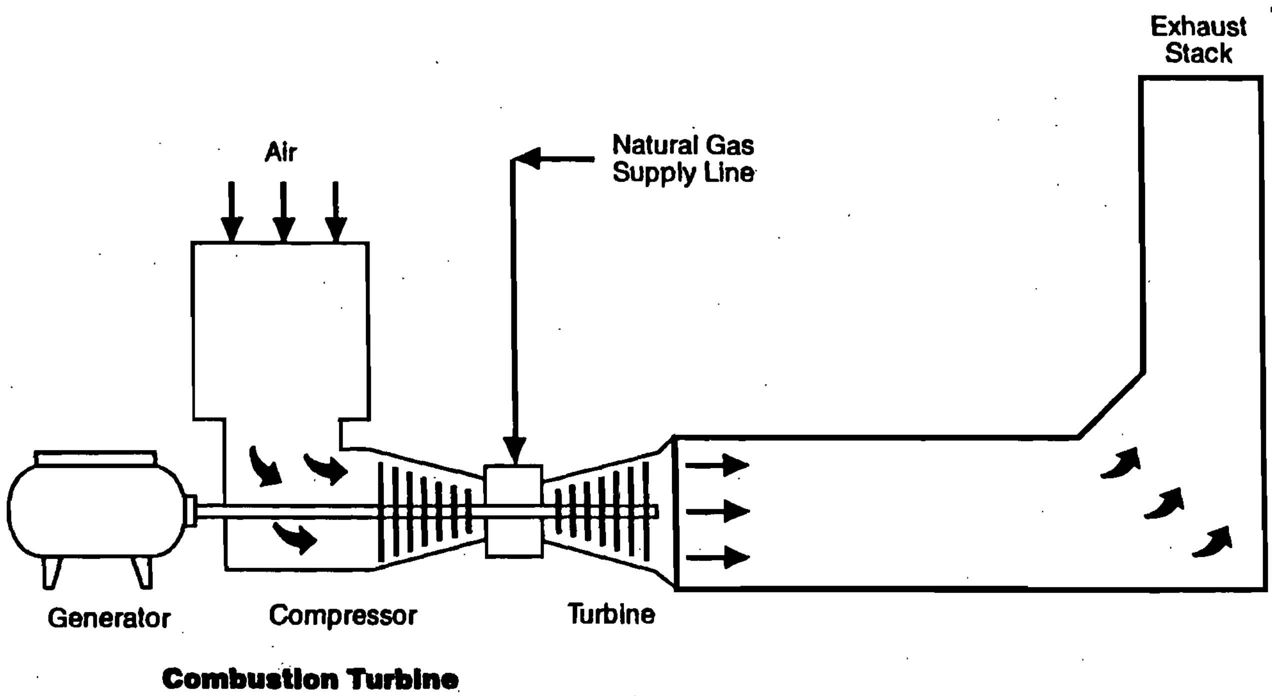
Attachment 5

III. Emission Unit Information

J. Emissions Unit Supplemental Information

1. Process Flow Diagram

Simple Cycle Combustion Turbine Process Flow Diagram



SIMPLE CYCLE COMBUSTION TURBINE

Attachment 6

III. Emission Unit Information

J. Emissions Unit Supplemental Information

2. Fuel Analysis or Specification

Fuel is specified as pipeline quality sweet natural gas and No. 2 fuel oil containing no more than 0.05 percent sulfur.

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FLORIDA GAS TRANSMISSION COMPANY
FERC Gas Tariff
Third Revised Volume No. 1

Third Revised Sheet No. 102C
Superseding
Second Revised Sheet No. 102C

GENERAL TERMS AND CONDITIONS
(continued)

am. GISB Definitions - shall mean any such definitions issued by GISB which have been adopted by the FERC. Transporter incorporates GISB Definitions (Version 1.3, July 31, 1998) 1.2.8 through 1.2.12 and 4.2.1 through 4.2.8 by reference herein.

2. QUALITY

A. Gas delivered by Shipper or for its account into Transporter's pipeline system at receipt points shall conform to the following quality standards:

1. shall be free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which might interfere with the merchantability of the gas stream, or cause interference with proper operation of the lines, meters, regulators, or other appliances through which it may flow;

2. shall contain not more than seven (7) pounds of water vapor per one thousand (1,000) MCF;

3. shall contain not more than one quarter (1/4) grain of hydrogen sulphide per one hundred (100) cubic feet of gas;

4. shall contain not more than ten (10) grains of total sulphur per one hundred (100) cubic feet of gas;

5. shall contain not more than a combined total three percent (3%) by volume of carbon dioxide and/or nitrogen;

6. shall contain not more than one quarter percent (1/4%) by volume of oxygen;

Issued by: Robert B. Kilmer, Vice President
Issued on: July 1, 1999

Effective: August 1, 1999

index of pages previous page next page

SPECIFICATIONS FOR #2 LOW SULFUR DIESEL FUEL

The oil shall be hydrocarbon oil, free from alkali, mineral acid, grit, fibrous or other foreign matter and shall meet the following physical and chemical properties:

1) Gravity: A.P.I. 30 minimum (ASTM D287)

2) Flash: 130 F minimum (ASTM D93)

3) Viscosity: Kinematic, Centistokes at 100 F, minimum 2.0, maximum 3.0 (ASTM D445)

4) Water & Sediment: .50% maximum, (ASTM D1796 or D2700)

5) Pour Point: 0 F maximum (ASTM D97)

6) Distillation: 10% Point, 480 F maximum, 90% Point, 640 F maximum, End Point 690 F maximum (ASTM D86)

7) Sulfur: Low Sulfur - 0.05% maximum (ASTM D129 or D1552),

8) BTU: minimum 138,000 BTU's per gallon (ASTM D240)

9) Carbon Residue on 10% bottoms: .25 Max (ASTM D189)

10) Trace Metals (PPM, Max):
Calcium 4.0
Lead 1.0
Potassium 2.0
Vanadium 1.5.

Attachment 7

III. Emission Unit Information

J. Emissions Unit Supplemental Information

3. Detailed Description of Control Equipment

The new simple cycle combustion turbine generator's (E/V 015) pollution control equipment consists of dry low NOx burners (DLN-2.6 combustors) and water injection to control emissions of NOx during natural gas and fuel oil firing, respectively. A detailed description of the control equipment is summarized in the attached Technical Evaluation and Preliminary Determination document.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Jacksonville Electric Authority

Kennedy Generating Station

170 Megawatt Simple Cycle Peaking Unit

Duval County

DEP File No. 0310047-002-AC

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

January 29, 1999

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Jacksonville Electric Authority (JEA)
21 West Church Street
Jacksonville, Florida 32202-3139

Authorized Representative: Walter P. Bussels, Managing Director & CEO

1.2 Reviewing and Process Schedule

10-30-98: Date of Receipt of Application
11-25-98: DEP completeness request
12-23-98: Application deemed complete.
01-26-99: Issued Intent

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figure 1. The JEA Kennedy Generating Station is located at 4215 Talleyrand Ave in Jacksonville, Duval County. The UTM coordinates of this facility are Zone 17; 440.0 km E; 3,591.0 km N.

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

The JEA Kennedy Generating Station produces electric power from three natural gas and fuel oil-fired steam units with a combined generating capacity of 250 megawatts (MW), a 21 MW natural gas and fuel oil-fired auxiliary boiler, and three No. 2 distillate fuel oil-fired simple cycle combustion turbines-electrical generator with a combined capacity of approximately 170 MW.

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. The present modification results in net emissions decreases or less-than-significant increases in PSD pollutants. Therefore the modification is not subject to PSD.

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

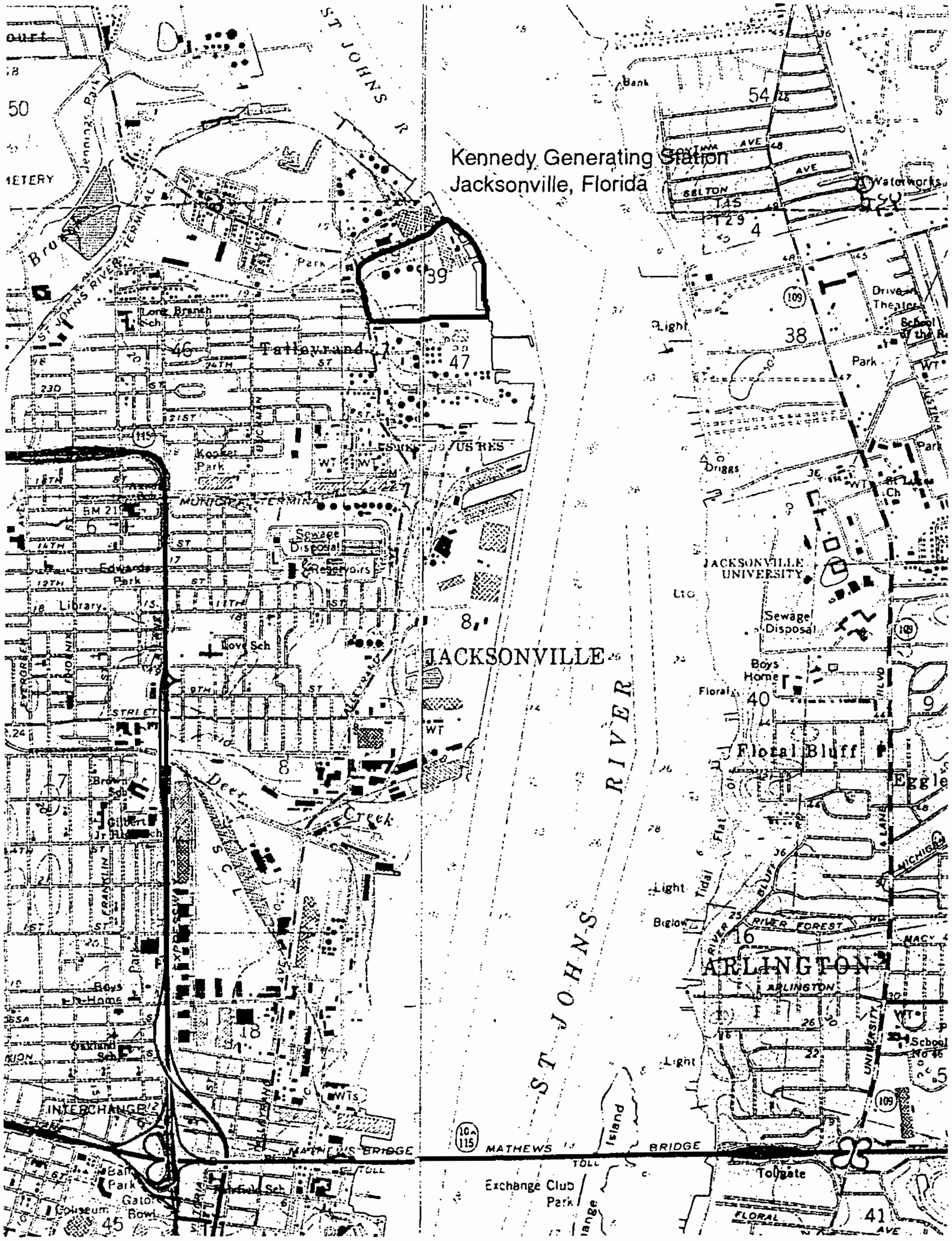


Figure 1 - Location of JEA kennedy Generating Station

3. PROJECT DESCRIPTION

This permit addresses the following emissions unit:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
00X	Power Generation	One 170 MW Combustion Turbine-Electrical Generator

JEA proposes to install a nominal 170 MW combustion turbine-electrical generator. The proposed unit is a General Electric PG 7241 FA combustion turbine that will burn natural gas and No. 2 distillate fuel oil. It will operate in simple cycle mode and intermittent duty. This turbine will replace an existing 150 MW natural gas and fuel oil-fired boiler identified by JEA as KE10 (ARMS Emission Unit 009) at the Kennedy Generating Station in Duval County. The project also includes a 90-foot new stack.

The prime mover and source of air polution will be a General Electric PG7241FA (7FA) combustion turbine-electrical generator. It will be equipped with Dry Low NO_X (DLN-2.6) combustors tuned to control NO_X emissions to 15 ppmvd at 15% O_2 between 50 and 100% of full load conditions durinng normal operations. Both natural gas and maximum 0.05 % sulfur fuel oil will be used in the unit.

A photgraph of a GE 7001FA (a predecessor of the PG 7241FA) is shown in Figure 2. An internal view is shown in Figure 3.

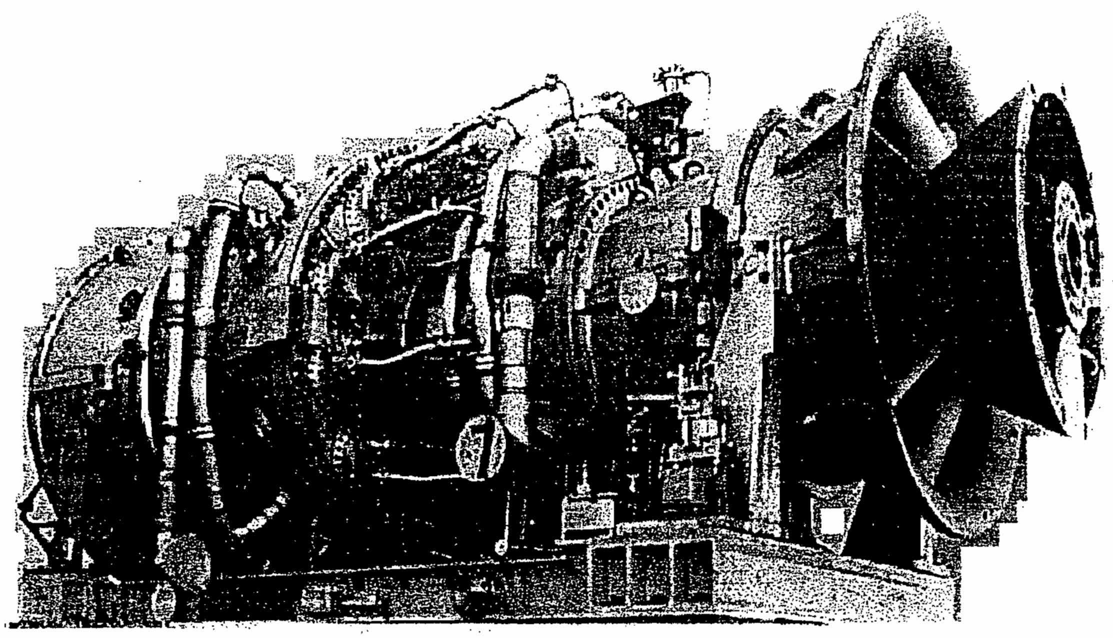


Figure 2 - Photograph of General Electric MS 7001FA Combustion Turbine

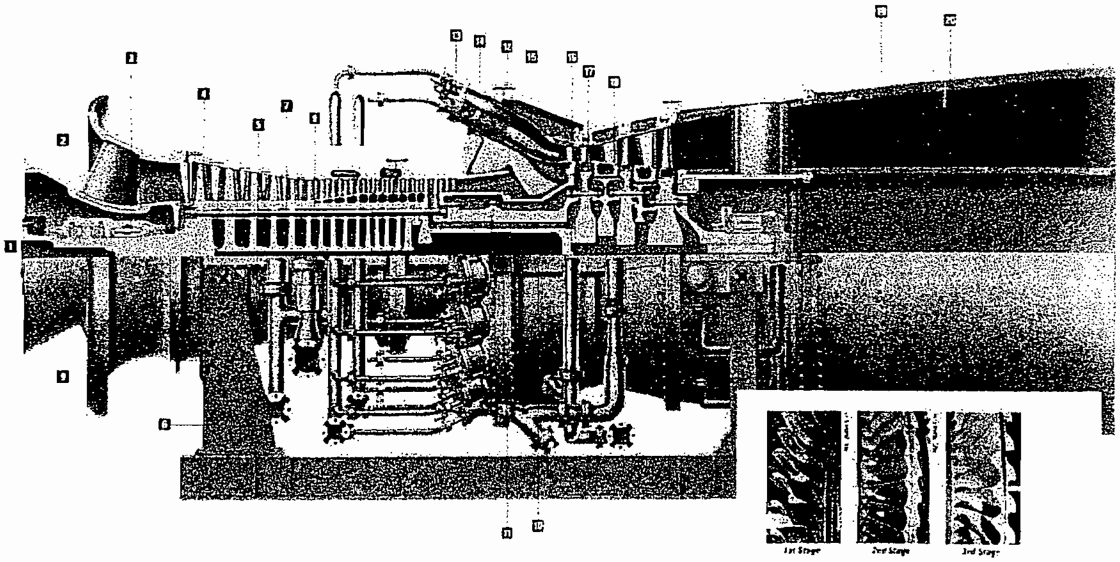


Figure 3 - Internal View of General Electric MS 7001FA Combustion Turbine

Hours of operation will be limited to 4050 hours per year on natural gas or 1260 hours per year on fuel oil. An algorithm is proposed by JEA to operate varying combinations of hours on natural gas and or fuel oil such that the maximum emissions do not exceed those related with exclusive firing of either fuel.

This combustion turbine will have a heat input of 1,623 million Btu per hour (natural gas) and 1822 million Btu per hour (fuel oil), *lower* heating value (MMBtu/hr, LHV) referenced to 59°F and 60 % relative humidity. At those heat input rates and conditions, the gross power output from the elcctrical generator is 173 MW for gas and 182 MW for oil. Depending on compressor inlet conditions, full load power capacity will range from approximately 150 to 187 MW while burning gas and 160 to 191 while burning fuel oil.

Emission decreases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist ($H_2SO_{4\ mist}$ or SAM), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). Net emission changes of these pollutants will be less than the significant emission levels per Table 62-212.400-2, F.A.C. Therefore review for the Prevention of Significant Deterioration (PSD) is not required.

According to the application, this unit will emit approximately 200 tons per year (TPY) of NO_X, 97 TPY of CO, 18 TPY of PM/PM_{10}, 62 TPY of SO_2, 6 TPY of VOC, and 6 TPY of SAM.

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines.[1] Project specific information is interspersed where appropriate.

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

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

In the JEA project, the unit will operate primarily as a peaking unit in the simple cycle mode. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is approximately 35 percent for F-Class combustion turbines in the simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat. Figure 4 is a process flow diagram for this simple cycle operation.

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the control technology section below.

5. RULE APPLICABILITY

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

This facility is located in Duval County, an area designated as unclassifiable for sulfur dioxide, as an air quality maintenance area for ozone and particulate matter in accordance with Rule 62-204.360, F.A.C. The proposed project is not subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the net emission increases for CO, VOC and NO_X do not exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

The net emissions increase/decrease for all PSD pollutants as a result of this modification are calculated below:

CONTEMPORANEOUS CREDITABLE CHANGES (TPY)

Pollutants	Past Emissions (Boiler KE10)	Future Emissions (170 MW CT)	Increase (decrease)	PSD Significance	PSD Review?
PM/PM_{10}	21.7	18.2	(3.5)	25/15	No
SAM	11.9	6.3	(5.5)	7	No
SO_2	266	62	(204)	40	No
NO_X	161.5	200.5	39	40	No
VOC	1.6	5.7	4.1	40	No
CO	14.5	97.2	82.7	100	No

This evaluation consists of a review of the control technology for PM/PM_{10}, VOC, CO, SO_2, and NO_X to insure that it is sufficient to restrict future emissions to levels lower than past emissions or net increases in emissions to levels less than the significant emission rates as described above. An analysis of the air quality impact from proposed project is required to insure that there are no exceedances of the National or State Ambient Air Quality Standards.

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

5.1 State Regulations

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

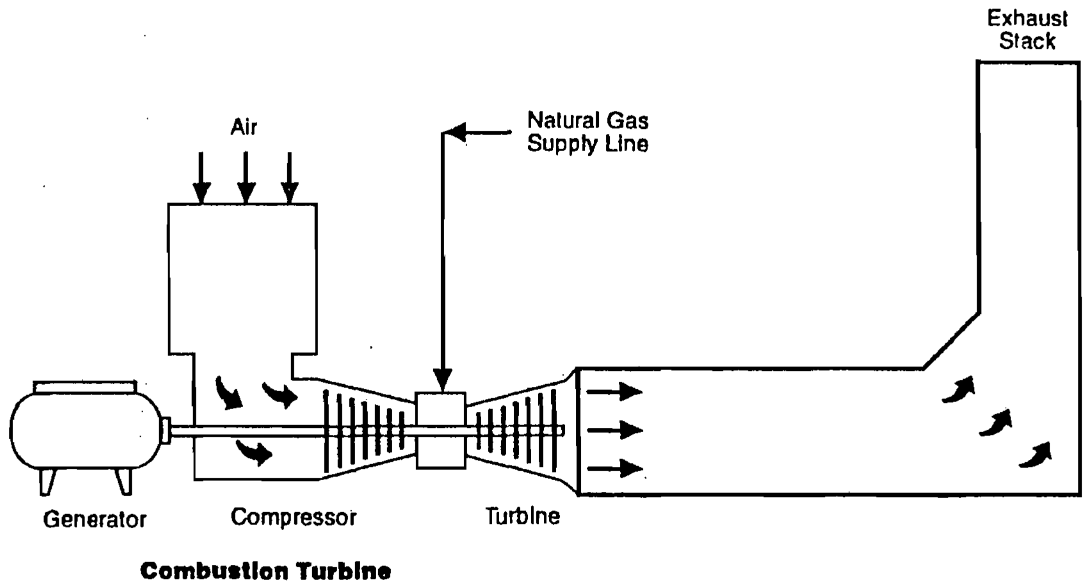


Figure 4 - Simple Cycle Combustion Turbine Process Flow Diagram

5.2 Federal Rules

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

6. AIR POLLUTION CONTROL TECHNOLOGY

6.1 Applicant Control Technology Proposal

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED LIMIT
PM/PM_{10} (Non-Condensables)	Combustion Controls	9 lb/hr (NG)* 17 lb/hr (F.O.)*
Volatile Organic Compounds	As Above	1.4 ppm (NG) 3.5 ppm (F.O.)
Carbon Monoxide	As Above	15 ppm (NG) 20 ppm (F.O.)
Sulfur Dioxide	As Above	2 gr/100 scf (NG) 0.05% Sulfur Fuel Oil
H_2SO_4	As Above	10 lb/hr
Opacity	As Above	5 (NG) 20 (F.O.)
Nitrogen Oxides	Dry Low NO_X - Natural Gas Wet Injection - Fuel Oil	15 ppm @ 15% O_2 (NG) 42 ppm @ 15% O_2 (F.O.)

6.2 Standards of Performance for New Stationary Sources

The minimum project control technology basis is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @15% O_2 (or <0.8% sulfur in fuel). The proposal is consistent with the NSPS which allows NO_X emissions over 100 ppm for the high efficiency unit to be purchased by JEA. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines.

6.3 Determinations by EPA and States

Recent Best Available Control Technology (BACT) proposals and determinations for NO_X in simple cycle gas turbine projects have ranged from 9 to 15 ppm @ 15% O_2 by Dry Low NO_X Combustion or Hot Selective Catalytic Reduction. Values whiel firing oil are typically 42 ppm by wet injection. In addition to being a simple cycle project, this unit will operate as a "peaker" and emissions will not trigger PSD and BACT. JEA has proposed a limits of 15 ppm for gas firing and 42 ppm for oil firing, which will avoid PSD. These are within the range of recent simple cycle, peaker BACT limits. Similarly, the proposed CO and VOC limits are within the range of recent BACT determinations for both simple and combined cycle projects.

6.4 Review of Combustion Turbine Control Technologies

A complete discussion of control options was not required because the project is not subject to a Best Available Control Technology Determination. However the applicant discussed the technology to be employed in order to comply with the New Source Performance Standards and the requested limits. The Department has included other information typically included in a complete BACT determination for comparison purposes.

6.4.1 Nitrogen Oxides Formation

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

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas.

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

6.4.2 NO_X Control Techniques

Combustion Controls

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

The above principle is depicted in Figure 5 for a General Electric can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

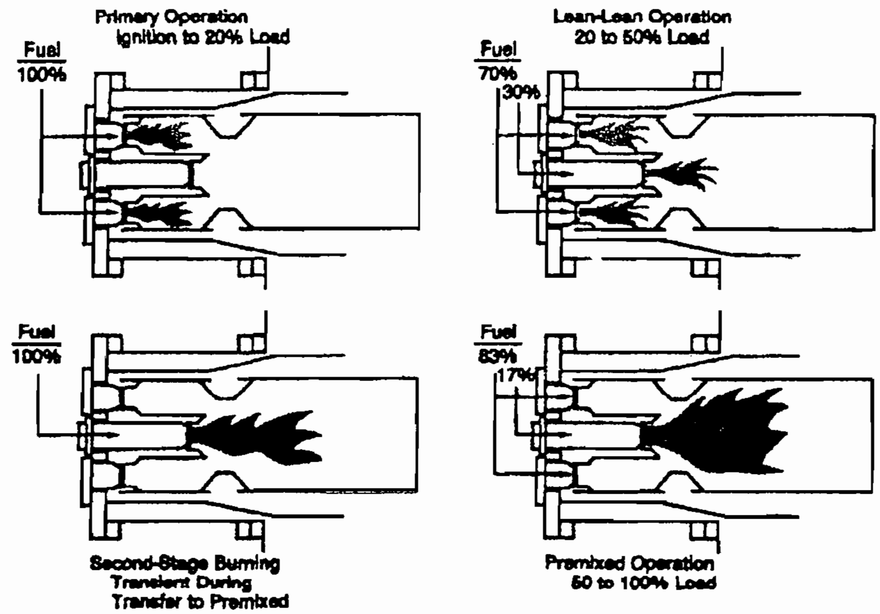
To further reduce NO_X emissions, GE developed the DLN-2 combustor (cross section shown in Figure 5) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and the combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

The emission characteristics of General Electric's DLN 2 combustors are given in Figure 6 (gas) and 7 (fuel oil). NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity.

Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the JEA project are shown in Figure 8. The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle to achieve emissions as low as 9 ppm of NO_X and 9 ppm of CO. The expected emission characteristics of General Electric's DLN 2.6 combustors, tuned for the proposed project, are given in Figure 9 (gas). Emissions characteristics while firing oil are expected to be the same as shown for the DLN-2 in Figure 7. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn are mostly non-VOC methane,

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



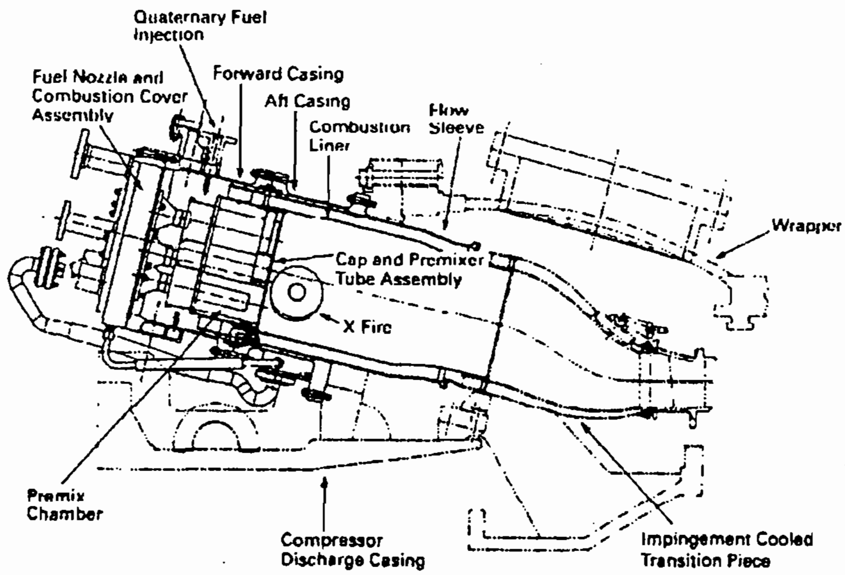


Figure 5 - Dry Low NOx Operating Modes - DLN-1

Cross Section of DLN-2.0

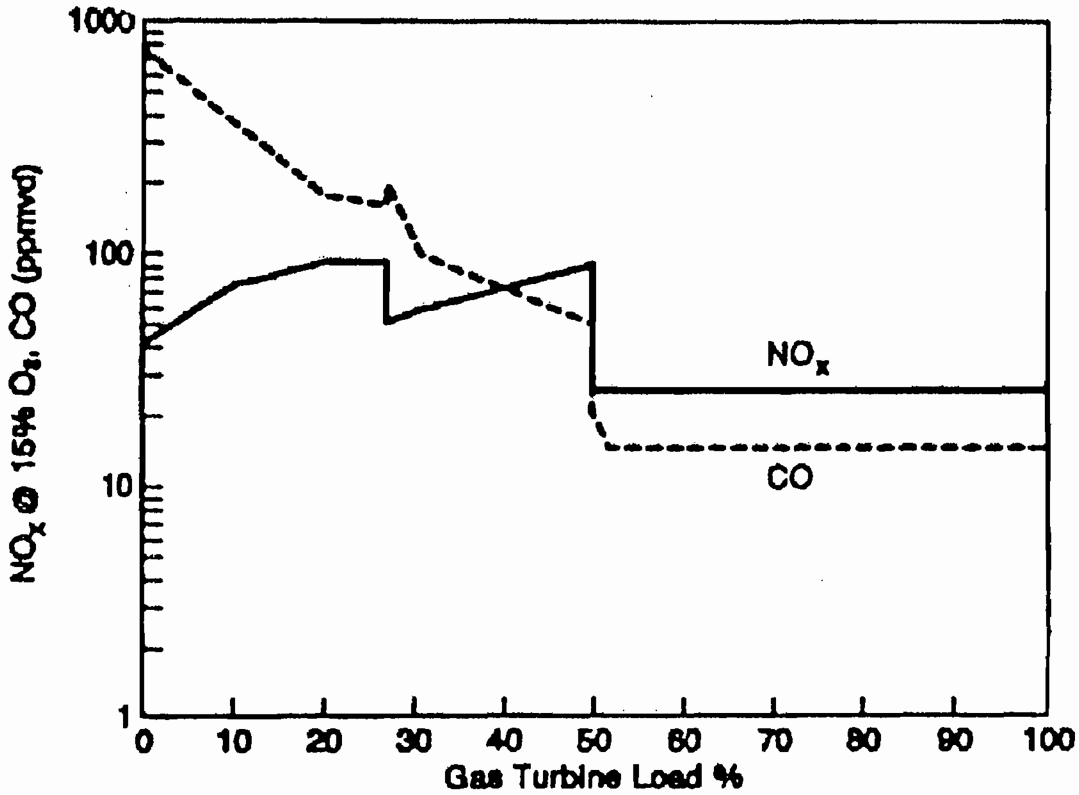


Figure 6 - Emissions Performance Curves for GE DLN-2 Combustor

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

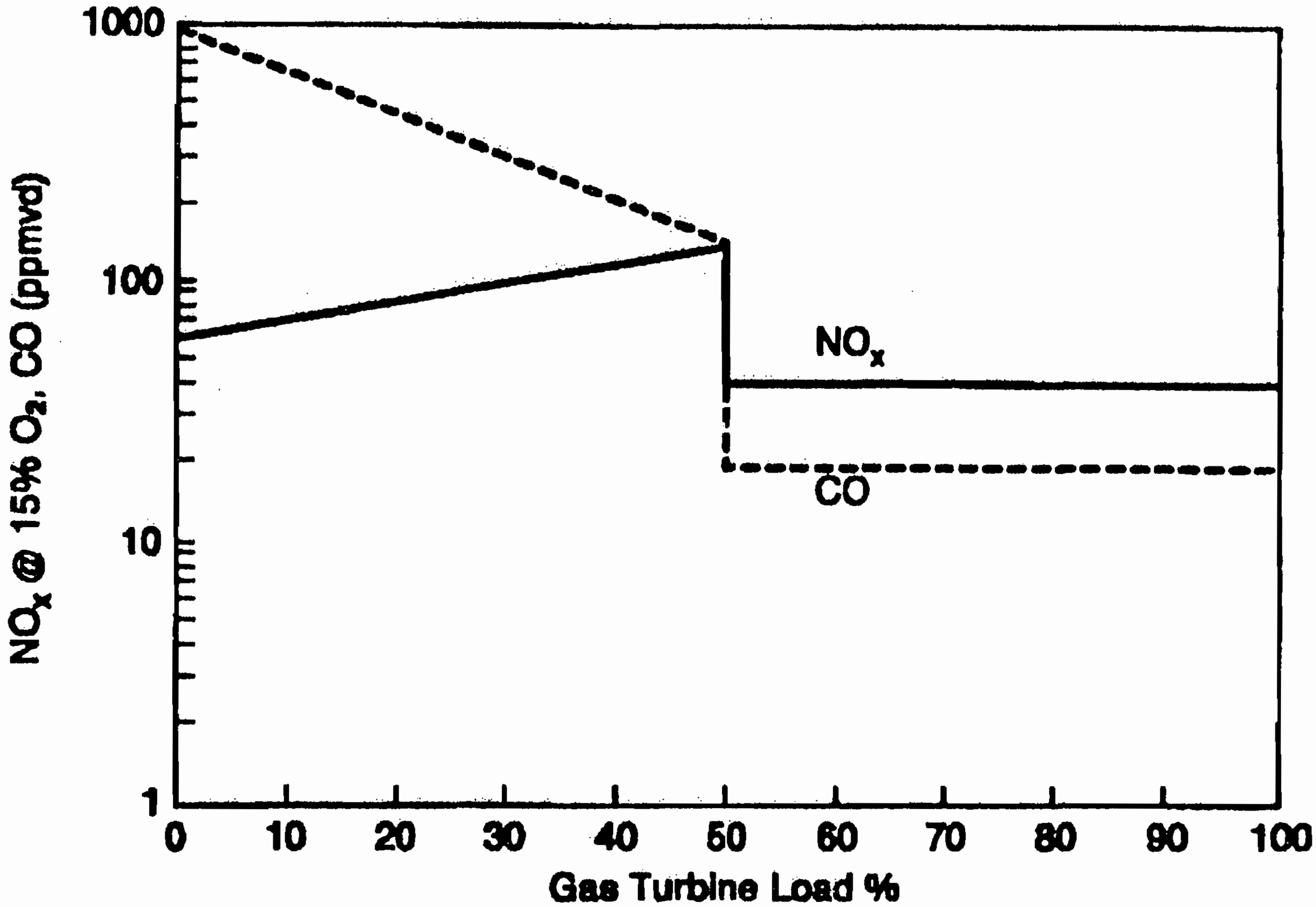


Figure 7 - Emissions Performance Curves for GE DLN-2 Combustor
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

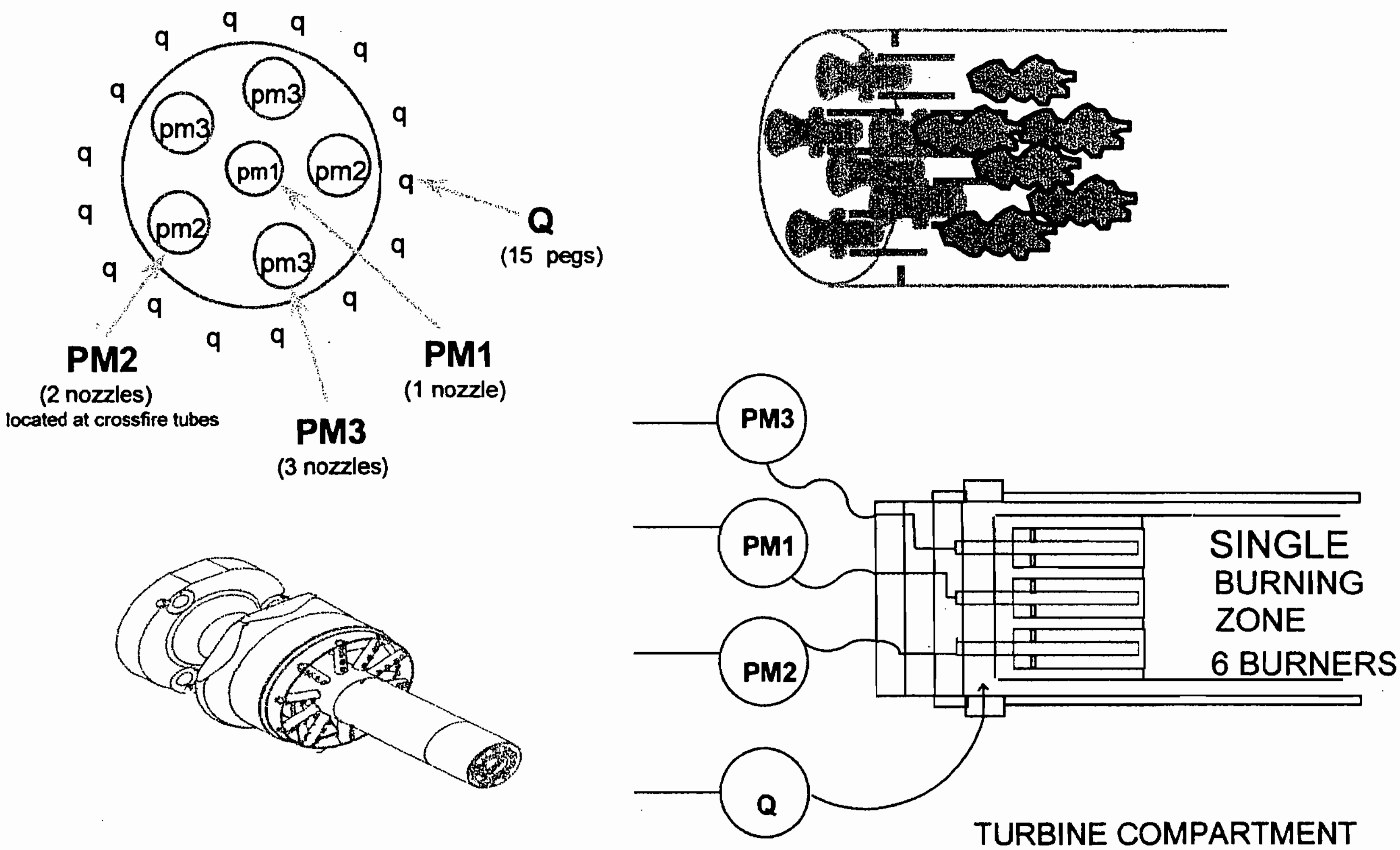


Figure 8 - GE DLN-2.6 Combustor and Nozzle Arrangement

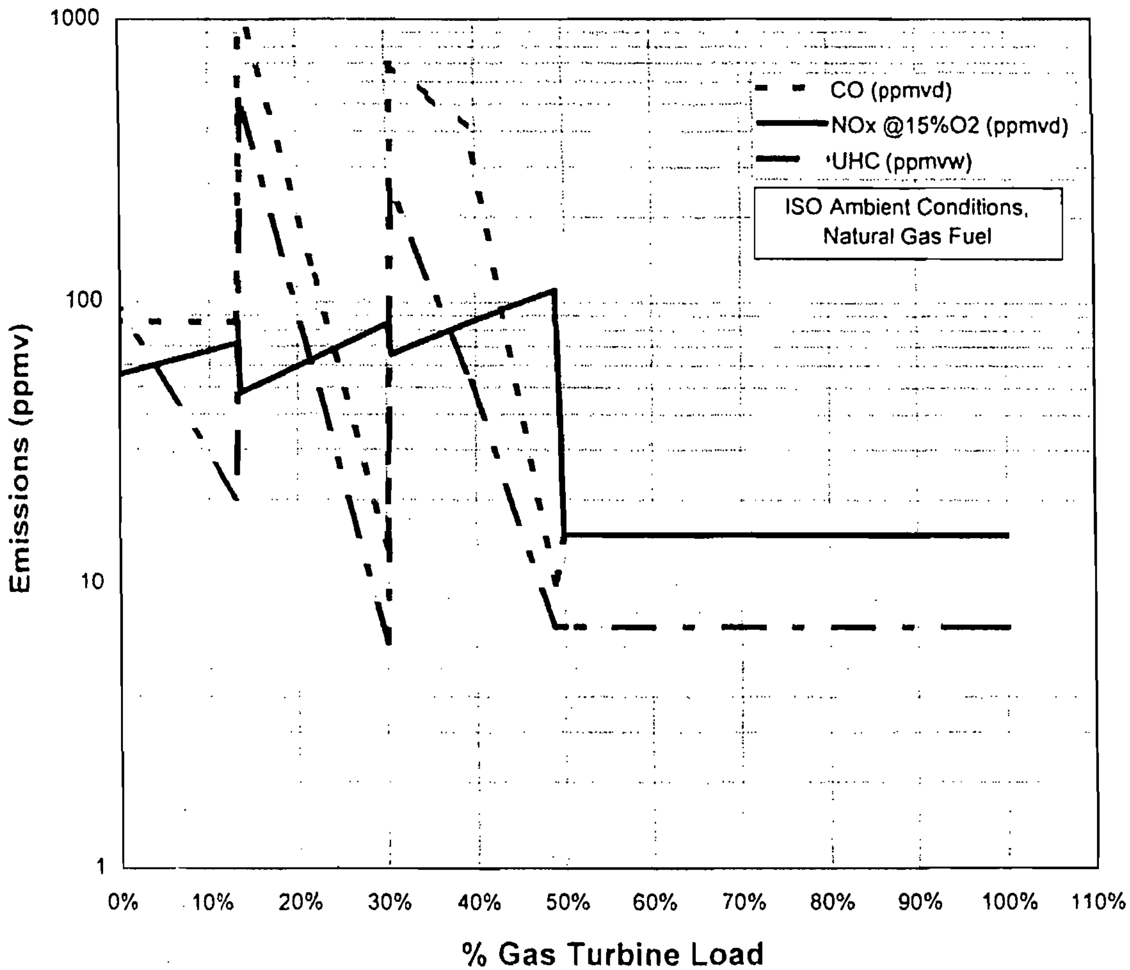


Figure 9 - Emissions Performance Curves for GE DLN-2.6 Combustor

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

(Simple Cycle, Intermittent Duty - If Tuned to 15 ppm NOx) back to the 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_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. 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_X formation can be appreciated from Figure 10 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle), such as the F class.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas. As of early 1992, over 100 gas turbine installations already used SCR in the United States. The only combustion turbines in Florida employing SCR are at the FPC Hines Energy Complex, where Westinghouse is unable to meet the DLN limits at the present time. Recently, FPC proposed a second construction phase incorporating SCR in two Westinghouse 501F combustion turbines. Seminole Electric recently advised the Department that it would install SCR in a previously Westinghouse 501F project, originally based on DLN. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date.

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

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

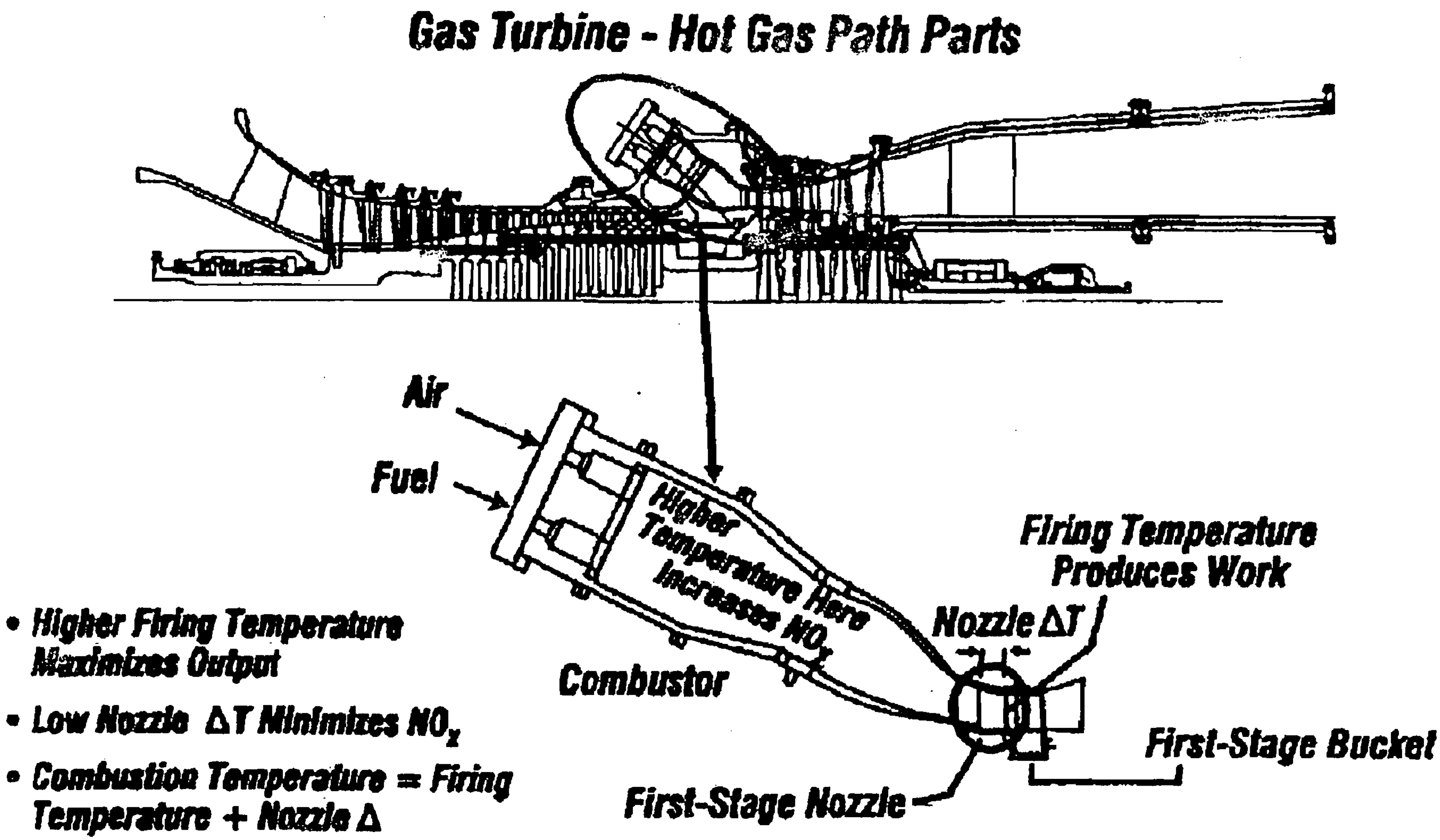


Figure 10 - Relation Between Flame Temperature and firing Temperature

6.4.3 Particulate Matter (PM/PM_{10}) Control

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

Natural gas and maximum 0.05 percent sulfur No. 2 fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be used contains minimal ash.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. This has been chosen as BACT by the applicant and the Department concurs. Annual emissions of PM/PM_{10} are expected to be less than 20 tons per year.

6.4.4 Carbon Monoxide (CO) Control

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

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 MW Berkshire, Massachusetts facility, 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Along with its recent proposal to install SCR on a Westinghouse 501F unit (Hardee Unit 3), Seminole Electric proposes to install an oxidation catalyst for CO control.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve CO emissions between 10 and 30 ppm at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the value of 15 ppm proposed JEA's application for gas firing appears relatively low, but consistent with the capabilities of the DLN-2.6 technology as discussed above. A CO limit of 20 ppm is proposed when burning oil. Annual emission are expected not to exceed 97 ton per year.

6.4.5 Volatile Organic Compound (VOC) Control

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 to 1.4 ppm (gas) and 3.5 (oil). These values are as low as any BACT-based VOC limit previously set by the Department. According to GE, even lower VOC emissions were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[2] Annual emissions of VOC are not expected to exceed 6 TPY.

6.5 Background on Selected Gas Turbine

JEA plans to install a nominal 170 MW General Electric MS7241FA combustion turbine to be operated in a simple cycle mode.

The first commercial GE 7F Class unit was a installed at the Virginia Power Chesterfield Station in 1990.[2] 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.[3] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppm These actually achieve less 25 ppm of NO_X and 15 ppm of CO. The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[4] Although permitted emissions are 12 ppm of NO_X, the City obtained a performance guarantee from GE of 9 ppm.[5]

General Electric, other manufacturers, and their customers are relying on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[6]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7 FA units met performance guarantees of 9 ppm with DLN-2.6 burners at Fort St. Vrain, CO and Clark County, WA.[7] GE has already achieved emissions of approximately 6 ppm on gas at a dual-fuel MW 7EA (120 MW combined cycle) unit at Cane Island Power Park in Kissimmee, FL.[8] The Cane Island unit is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line and performance guarantees less than 9 ppm can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[9]

6.6 Control Technology Determination

Following are the emission limits determined for the JEA project assuming full load. *Values for NO_X are corrected to 15% O_2 on a dry basis.* These limits or their equivalents in terms of pounds per hour, are given in the permit Specific Conditions.

NO_X	SO_2	CO	VOC	PM/Visibility (% Opacity)	Technology and Comments
15 ppm (NG) 42 ppm (FO)	<2gr S/100scf of gas 0.05% S in FO	15 ppm (NG) 20 ppm (FO)	1.4 ppm (NG) 3.5 ppm (FO)	10	Dry Low NO_X Combustors Wet Injection Pipeline Natural Gas Good Combustion Fuel Oil, 0.05% Sulfur

6.7 Rationale for Control Technology Determination

- JEA obtained a guarantee from GE for DLN-2.6 combustors which have been demonstrated to meet all of the above limits on "7FA" Class gas turbines.
- The JEA project "nets out" of PSD review and BACT.
- All of the combustion turbine emission limits comply with the NSPS and are close or equal to recent Department BACT determinations applicable to new units at start-up.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department, with JEA's concurrence, will set a visible emission standard of 10 percent opacity.
- The Department will set CO limits achievable by good combustion equal to 15 ppm on gas and 20 ppm on oil. CO limits for the FPL Fort Myers Repowering Project and the Santa Rosa Energy Center are 12 ppm on gas. Similar limits have been proposed in recently issued Intents for Kissimmee Utilities Cane Island Unit 3 and the Duke Energy New Smyrna Beach Power Project.
- VOC emissions of 1.4 ppm (gas) and 3.5 (oil) proposed by JEA are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels with the DLN-2.6 combustors while firing natural gas.
- SO_2 and $H_2SO_{4\text{Acid Mist}}$ emissions compliance will be implemented through the Custom Fuel Monitioring Schedule for each allowed fuel.

6.8 Compliance Procedures

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

7. SOURCE IMPACT ANALYSIS

An air quality analysis was not required because the modification is not subject to PSD review.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

A. A. Linero, P.E.
Teresa Heron, Review Engineer

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[4] Davis, L.B. :Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines. 1994.
[5] Florida DEP. PSD Permit, City of Tallahassee Purdom Unit 8. May, 1998.
[6] City of Tallahassee. PSD/Site Certification Application. April, 1997.
[7] State of Alabama. PSD Permit, Alabama Power/Barry (GE 7FA).
[8] Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program.
[9] Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.
[10] Telecon. Schorr, M., GE, and Linero, A. A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.

Attachment 8

III. Emission Unit Information
J. Emissions Unit Supplemental Information
4. Description of Stack Sampling Facilities

The new simple cycle combustion turbine generator (E/V 015) has a stack sampling platform at the 70 ft (approximately) level of the stack. The stack diameter at the sampling ports is 18 ft. There are four sampling ports available for emission testing. The sampling ports are 40 inches in diameter and have 20 inch nipples. Stack sampling platform access is available via a caged latter. The stack sampling facilities were installed in accordance with Rule 62-297.310(6) (attached), as required by Air Construction Permit No. 0310047-002-AC.

(5) Determination of Process Variables.

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

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

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d). Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e). Access to Work Platform.

1 Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g). Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

(7) Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

Attachment 9

III. Emission Unit Information
J. Emissions Unit Supplemental Information
6. Procedures for Startup and Shutdown

Procedures for startup and shutdown will be completed in accordance with the manufactures' operating procedures. Excess emissions resulting form startup and shutdown are permitted in condition 22 of the construction permit (No. 0310047-002-AC).

Attachment 10

III. Emission Unit Information
J. Emissions Unit Supplemental Information
11. Alternative Methods of Operation

Alternative methods of operation include the use of pipeline quality natural gas and 0.05 percent sulfur NO. 2 or superior grade of fuel oil.

Attachment 11

III. Emission Unit Information

J. Emissions Unit Supplemental Information

15. Acid Rain Part Application

Phase II Permit Application

Page 1

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: [X] New [ ] Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	JD Kennedy	State	FL	ORIS Code	0666

STEP 2 Enter the boiler ID# from NADB for each affected unit and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

	Compliance Plan			
a	b	c	d	e
Boiler ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date *	New Units Monitor Certification Deadline
015**	Yes		April 2000	July 2000
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes for any unit

[ ] For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

* Estimated
** Presumed Account ID #000666000015

Plant Name (from Step 1) JD Kennedy

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1) JD Kennedy

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jon P. Eckenbach	
Signature	Date 7/19/99

Acid Rain Program
Instructions for
Phase II Permit Application
(40 CFR 72.30- 72.31 and Rule 62-214.320, F.A.C.)

The Acid Rain Program regulations require the designated representative to submit an Acid Rain part application for Phase II for each source with an Acid Rain unit. A complete Phase II part application is binding on the owners and operators of the Acid Rain source and is enforceable in the absence of a permit until the permitting authority either issues a permit with an Acid Rain part to the source or disapproves the application.

Please type or print. The alternate designated representative may sign in lieu of the designated representative. If assistance is needed, contact the permitting authority.

STEP 1 NADB is the National Allowance Data Base for the Acid Rain Program. To obtain the database on diskette, call the Acid Rain Hotline at (202) 233-9620. This data file is in dBase format for use on an IBM-compatible PC. It requires 2 megabytes of hard drive memory. If the unit is not listed in NADB, use the plant name, ORIS Code, and Boiler ID listed on the certificate of representation for the plant.

STEP 2 The monitor certification deadline is determined in accordance with 40 CFR 75.4. If the commence operation date or monitor certification date changes after the Phase II permit is issued, the source must submit a request for an administrative permit amendment.

STEP 5 "AIRS" is the Aerometric Information Retrieval System operated by EPA's Office of Air Quality Planning and Standards. The AIRS number for a source has 12 digits. "FINDS" is the Facility Indexing System. It provides an Agency-wide ID number to cross-identify facilities in all EPA data systems. Please enter these numbers if they are available; this step is optional.

Submission Instructions

For initial Phase II permit applications: If, by **November 15, 1995**, the State or local jurisdiction (*e.g.*, District, County, or City) in which the source is located has both (1) an acid rain program identified in a Federal Register notice as acceptable to the Administrator and (2) an operating permits program granted full or interim approval by the Administrator in a Federal Register notice, mail this form and three copies to that state or local authority. If not, mail this form and one copy to the EPA regional office and two copies to the State or local jurisdiction in which the source is located.

If you have questions regarding this form, contact your local, State, or EPA regional representative, or call EPA's Acid Rain Hotline at (202) 233-9620.