21 West Church Street
Jacksonville, Florida 32202-3139

JEA

RECEIVED
OCT 30 1998
BUREAU OF AIR REGULATION

October 29, 1998

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Air Construction Permit Application for
Kennedy Generating Station Combustion Turbine
0310047-002-AC

Dear Mr. Fancy:

Attached to this letter please find a copy of the air construction permit application for the installation of a simple cycle combustion turbine (CT) at Jacksonville Electric Authority's (JEA's) Kennedy Generating Station. This application has been prepared on DEP Form No. 62-210.900(1) in accordance with the applicable instructions for this form.

Background:

JEA proposes to construct a 170 MW natural gas (NG) and No. 2 fuel oil (FO) fired electrical generating CT at the existing Kennedy Generating Station in Jacksonville, Florida. The proposed CT would replace an aging NG and FO fired boiler (KE10) and will be used to provide peaking electrical power to the grid. KE10 would be taken out of service once the CT becomes operational. It is anticipated that construction of this project will begin on June 1, 1999 with operation commencing following completion of construction about May 1, 2000.

While previous correspondence with the DEP about this project, including the February 12, 1998 "Request for PSD Determination" (attached), indicated that a particular CT had not yet been selected for the project, a CT has now been selected. The CT proposed for this project is one of two mentioned in our previous correspondence, the General Electric PG 7241 FA model. Emissions data for this CT have been included as an attachment to the permit application.

PSD Applicability:

The proposed CT is being permitted as a minor source due to its limited hours of operation and the contemporaneous shutdown of KE10. The "netting analysis" to determine PSD applicability is documented in the February 12, 1998 "Request for PSD Determination" report previously submitted to your department. This analysis determined that based on the historical use of the existing KE10 boiler, the proposed CT could operate several hundred hours per year on either NG or FO without exceeding applicable Prevention of Significant Deterioration (PSD) major source significance levels.

This analysis has recently been updated to include the most recent twenty-four months of operation for the KE10 boiler, resulting in increased allowable hours of operation for the proposed CT while still remaining a minor source.

These hours are determined by a formula establishing a maximum number of hours of operation on NG (4,050 hours) which the proposed CT can operate without exceeding the PSD significance levels. Operation on FO, with its higher associated emissions, results in a lower maximum number of hours of operation (1,260 hours). Due to potential NG fuel supply curtailments and economic considerations, normal operations of the proposed CT may result in the CT being fired with both NG and FO in any twelve month period. Therefore, a formula was derived to determine the maximum number of hours of FO and NG firing annually allowed. This requires that the actual number of hours of operation on FO be subtracted from the maximum number of allowed hours of operation on natural gas to determine the overall number of hours of operation on either fuel in any twelve month period. This formula is expressed as follows:

MAXHRSNG = 4,050 - 3.215*ACTHRSFO

Where: MAXHRSNG = The maximum number of hours on natural gas (4,050) in any twelve month period.
ACTHRSFO = The actual hours of hours of operation in any twelve month period, not to exceed 1,260 hours.

Note that this is essentially the same formula used in the February 12, 1998 "Request for PSD Determination" which resulted the DEP determination that the proposed project was classified as a minor modification to an existing major source. The only change to this formula is due to the increased use of the KE10 boiler in the last twenty-four months. JEA proposes that this formula be used as a specific condition of the permit in order to determine compliance with applicable regulations. This is discussed further in Attachment 5 of the permit application.

Ambient Air Quality Analysis:

Because the proposed project was determined to be a minor modification as a result of the netting analysis, no dispersion modeling was required.

Continuous Emissions Monitoring:

JEA notes that the proposed CT, producing more than 25 MW, will be subject to the monitoring requirements of 40 CFR 60 Subpart GG due to the required water injection during FO firing, and the continuous emissions monitoring (CEM) requirements of 40 CFR Subpart 75, the Acid Rain Program. 40 CFR 60 Subpart GG requires the owner or operator of any stationary gas turbine using water injection to control NOx emissions, to install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio of water to fuel being fired in the turbine to determine compliance with these provisions. This project will use water injection during periods of FO firing only. Sampling of the fuel for nitrogen and sulfur content is also required under these provisions in order to demonstrate compliance.

The Acid Rain Program also requires the owner or operator to measure opacity and SO2, NOx, and CO2 emissions from each affected unit. Because JEA intends to operate the CT as a gas-fired peaking unit, certain alternatives to the physical installation of CEMs are available under this regulation in Appendices D, E and G of 40 CFR 75. In order to be classified as a gas fired peaking unit under this regulation, JEA must ensure that:

1. The three year average annual heat input from natural gas is greater than or equal to 90 percent. It must also not have fired more than 15 percent oil in any one of the three averaging years.

2. The three year average annual capacity factor is not greater than 10 percent.

3. The highest annual capacity factor is not greater than 20 percent.

Given these requirements, JEA proposes to:

1. Install fuel flow meters to measure, and a digital acquisition system to record, the amount of fuel used on an hourly basis.

2. Record the load and heat input rate.

3. Perform fuel sampling and analysis, for gas or oil, as appropriate, to enable the calculation of SO2, NOx, and CO2 on an hourly basis using the fuel flow measured above.

4. Install an opacity monitor and other required CEMs in accordance with 40 CFR part 75, the Acid Rain program.

Should you have any questions regarding the information in this letter or the permit application, please do not hesitate to call me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Group

NBG

KGSCT

Enclosure
cc: Amy Carlson, Black & Veatch
Marty Costello, FDEP

CC: NED
Duval Co
T. Heron, BAR

RECEIVED

OCT 30 1998

BUREAU OF
AIR REGULATION

Air Construction Permit Application

for the

Jacksonville Electric Authority

Kennedy Generating Station

October 1998

FLORIDA DEP LOGO

Department of Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

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

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

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

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	Oct 30 1998
2. Permit Number:	0310047-002-AC
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Walter P. Bussels Managing Director & Chief Executive Officer
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Jacksonville Electric Authority Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202-3139
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* of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., 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 10/26/98 Date

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID	Description of Emissions Unit	Permit Type
014	170 MW Combustion Turbine	AC1B

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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: ______________________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: ______________________

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ______________________

Operation permit to be revised: ______________________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: ______________________

[ ] Air operation permit revision for a Title V source 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 to be revised: ______________________

Reason for revision: ______________________

____

Category II: All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______________________

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______________________

Reason for revision: ______________________

____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain:

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: ______________________

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

Current operation permit number(s): ______________________

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

Application Processing Fee

Check one:

[ ] Attached - Amount: ______________ [X] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations: JEA proposes to construct a 170 MW natural gas (NG) and #2 fuel oil (FO) fired simple cycle combustion turbine (CT) electrical generating unit at the existing Kennedy Generating Station in Jacksonville, Florida. The proposed CT would replace an aging NG and FO fired boiler (KE10) and will be used as a peaking unit. KE10 would be taken out of service once the CT becomes operational. The CT proposed for this project is a General Electric PG7241 FA (GE PG7241 FA).
2. Projected or Actual Date of Commencement of Construction: June 1, 1999
3. Projected Date of Completion of Construction: May 1, 2000

Professional Engineer Certification

1. Professional Engineer Name: Anthony L. Compaan Registration Number: PE-0045662
2. Professional Engineer Mailing Address: Organization/Firm: Black & Veatch Street Address: JEA Tower 21 West Church Street, T-10 City: Jacksonville State: FL Zip Code: 32202-3139
3. Professional Engineer Telephone Numbers: Telephone: (904) 665 - 7867 Fax: (904) 665 – 7263

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 [ ] 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.

Anthony L. Compaan 10/26/98

Signature Date

ANTHONY LEE COMPAAN
CERTIFICATE
No 0045662
STATE OF FLORIDA
REGISTERED ENGINEER

(seal)

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact N. Bert Gianazza, P.E. Environmental Health & Safety group
2. Application Contact Mailing Address: Organization/Firm: Jacksonville Electric Authority Street Address: 21 West Church Street City: Jacksonville State: Florida Zip Code: 32202-3139
3. Application Contact Telephone Numbers: Telephone: (904) 665-6247 Fax: (904) 665-7376

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17 East (km): 440000 North (km): 359100			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
3. Governmental Facility Code:	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: N. Bert Gianazza, P.E.
2. Facility Contact Mailing Address: Organization/Firm: Jacksonville Electric Authority Street Address: 4125 Talleyrand Ave. City: Jacksonville State: Florida Zip Code: 32206
3. Facility Contact Telephone Numbers: Telephone: (904) 665-6247 Fax: (904) 665-7376

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes [X] No [ ] Unknown
2. Title V Source? [X] Yes [ ] No
3. Synthetic Non-Title V Source? [ ] Yes [X] No
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [X] Yes [ ] No
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes [X] No
6. Major Source of Hazardous Air Pollutants (HAPs)? [ ] Yes [X] No
7. Synthetic Minor Source of HAPs? [ ] Yes [X] No
8. One or More Emissions Units Subject to NSPS? [X] Yes [ ] No
9. One or More Emission Units Subject to NESHAP? [ ] Yes [X] No
10. Title V Source by EPA Designation? [ ] Yes [X] No
11. Facility Regulatory Classifications Comment (limit to 200 characters):

B. FACILITY REGULATIONS

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following.

General

Air emissions units must obtain an air construction permit prior to construction or Modification. Construction permits shall not be issued to any emissions unit that would Cause or contribute to a violation of the ambient air quality standards or exceeds the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting requirements

The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60 Subpart GG	
40 CFR 72	
40 CFR 73	
40 CFR 75	
FAC 62-204	
FAC 62-210	
FAC 62-212.100 - 300	
FAC 62-213.400	
FAC 62-214	
FAC 62-296.410	
FAC 62-297	

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
NOx	A
CO	SM
VOC	B
SO2	SM
PM10	B
Pb	B
SAM	SM

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information: Pollutant _____ of _____

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

Facility Pollutant Detail Information: Pollutant _____ of _____

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location: [X] Attached, Document ID:___1____ [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID:___2____ [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID:___3____ [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID:___4____ [ ] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID:___5____ [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
8. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
9. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable
10. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:_______ [ ] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID:_______ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached, Document ID:_______ [ ] Plan to be Submitted to Implementing Agency by Required Date [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:_______ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:_______ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L 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. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

<u>Type of Emissions Unit Addressed in This Section</u>

1. 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. Single Process, Group of Processes, or Fugitive Only? 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): 170 MW dual-fuel simple cycle combustion turbine		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown 014		
3. Emissions Unit Status Code: C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): This emissions unit will be a GE PG7241 FA combustion turbine.		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): Low NOx burners.
2. Control Device or Method Code: 024

B.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:		
2. Long-term Reserve Shutdown Date:		
3. Package Unit: GE PG7241 FA Manufacturer:	Model Number:	
4. Generator Nameplate Rating: 170	MW	
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate: GE PG7241 FA = 1,736 (NG) 1,905 (FO)		mmBtu/hr (LHV)
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:		
	hours/day 24	days/week 7
	weeks/year 52	hours/year above

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

This unit is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following.
General
Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceeds the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60 subpart GG	
40 CFR 72	
40 CFR 73	
40 CFR 75	
FAC 62-204	
FAC 62-210	
FAC 62-212.100 - 300	
FAC 62-213.400	
FAC 62-214	
FAC 62-296.410	
FAC 62-297	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: 014
2. Emission Point Type Code: [X] 1 [ ] 2 [ ] 3 [ ] 4
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [X] V [ ] W
6. Stack Height: 90 feet
7. Exit Diameter: 24 feet
8. Exit Temperature: 1116 °F

9. Actual Volumetric Flow Rate: 2,370,000	acfm
10. Percent Water Vapor : 8.4	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: 17 East (km): 440000 North (km): 3359100	
14. Emission Point Comment (limit to 200 characters): This data is representative of emissions during operation at normal conditions when firing NG.	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment _1___ of _2___

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Natural gas firing.	
2. Source Classification Code (SCC): 20100201	
3. SCC Units: lb/mmcf burned	
4. Maximum Hourly Rate: 1.85 mmscf/hr	1. Maximum Annual Rate: 5,403 mmscf
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 937 (LHV)	
10. Segment Comment (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx	024		EL
CO			NS
VOC			NS
SO2			NS
PM10			NS
SAM			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NO_X		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions: GE PG7241 FA	lb/hour 401	tons/year 200.48
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: Vendor data		
7. Emissions Method Code: [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): Based on vendor supplied data (attached).		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

Emissions Unit Information Section ______ of ______

Allowable Emissions (Pollutant identified on front of page)

A.

1.	Basis for Allowable Emissions Code: ESCPSD
2.	Future Effective Date of Allowable Emissions:
2.	Requested Allowable Emissions and Units: Other – hrs. of operation per fuel type per 12 month period.
4.	Equivalent Allowable Emissions: lb/hour tons/year GE PG7241 FA 401 200.48
5.	Method of Compliance (limit to 60 characters): Recordkeeping – hrs. of operation per fuel type per 12 month period.
6.	Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).

B.

1.	Basis for Allowable Emissions Code: RULE
2.	Future Effective Date of Allowable Emissions:
3.	Requested Allowable Emissions and Units: 75 ppmv @15% O2, dry basis
4.	Equivalent Allowable Emissions: lb/hr tons/year GE PG7241 FA 575 2,518.5
4.	Method of Compliance (limit to 60 characters): Monitoring and recordkeeping of nitrogen content of fuel.
6.	Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60.332 (a)(1)

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: CO		
2. Total Percent Efficiency of Control:	%	
3. Potential Emissions: GE PG7241 FA	lb/hour 1,759	tons/year 97.2
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: Reference: Vendor data		
7. Emissions Method Code: [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): Based on vendor supplied data (attached).		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: VOC		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions: GE PG7241 FA	lb/hour 55.8	tons/year 5.67
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: Vendor data		
7. Emissions Method Code: [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): Based on vendor supplied data (attached).		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

Emissions Unit Information Section ______ of ______

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: ESCPSD		
2. Future Effective Date of Allowable Emissions:		
2. Requested Allowable Emissions and Units: Other – hrs. of operation per fuel type per 12 month period.		
4. Equivalent Allowable Emissions:	lb/hour	tons/year
GE PG7241 FA	55.8	5.67
5. Method of Compliance (limit to 60 characters): Recordkeeping – hrs. of operation per fuel type per 12 month period.		
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

B.

1. Basis for Allowable Emissions Code:		
3. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lb/hr	tons/year
5. Method of Compliance (limit to 60 characters):		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60.332 (a)(1)		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: lb/hour tons/year

	lb/hour	tons/year
GE PG7241 FA	98	61.74

4. Synthetically Limited?
   [X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
   [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
   Reference: Vendor data

7. Emissions Method Code:
   [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):
   Based on vendor supplied data (attached).

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

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

Emissions Unit Information Section ______ of ______

Allowable Emissions (Pollutant identified on front of page)

A.

1.	Basis for Allowable Emissions Code: ESCPSD
2.	Future Effective Date of Allowable Emissions:
3.	Requested Allowable Emissions and Units: Other – hrs. of operation per fuel type per 12 month period.
4.	Equivalent Allowable Emissions: lb/hour tons/year GE PG7241 FA 98 61.74
5.	Method of Compliance (limit to 60 characters): Recordkeeping – hrs. of operation per fuel type per 12 month period.
6.	Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).

B.

1.	Basis for Allowable Emissions Code: RULE
2.	Future Effective Date of Allowable Emissions:
3.	Requested Allowable Emissions and Units: 0.8% sulfur in fuel
4.	Equivalent Allowable Emissions: lb/hr tons/year GE PG7241 FA 1,522 6,665
5.	Method of Compliance (limit to 60 characters): Monitoring and recordkeeping of sulfur content of fuel.
6.	Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60.333 (b)

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM10

2. Total Percent Efficiency of Control: %

3. Potential Emissions:

	lb/hour	tons/year
GE PG7241 FA	17.0	18.23

4. Synthetically Limited?
   [X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
   [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year

6. Emission Factor:
   Reference: Vendor data

7. Emissions Method Code:
   [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):
   Based on vendor supplied data (attached).

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

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

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: ESCPSD		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: Other – hrs. of operation per fuel type per 12 month period.		
4. Equivalent Allowable Emissions:	lb/hour	tons/year
GE PG7241 FA	17.0	18.23
5. Method of Compliance (limit to 60 characters): Recordkeeping – hrs. of operation per fuel type per 12 month period.		
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

B.

1. Basis for Allowable Emissions Code: RULE		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: 0.1 lb / mmBtu		
4. Equivalent Allowable Emissions:	lb/hr	tons/year
GE PG7241 FA	1,832	8,024
5. Method of Compliance (limit to 60 characters): Recordkeeping of hours of operation and load.		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): FAC 62-296.410 (2) (b) 2		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SAM		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	lb/hour	tons/year
GE PG7241 FA	10	6.3
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year		
6. Emission Factor: Reference: Vendor data		
7. Emissions Method Code: [ ] 0 [X] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): Based on vendor supplied data (attached).		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: ESCPSD		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: Other – hrs. of operation per fuel type per 12 month period.		
4. Equivalent Allowable Emissions: GE PG7241 FA	lb/hour 10	tons/year 6.3
5. Method of Compliance (limit to 60 characters): Recordkeeping – hrs. of operation per fuel type per 12 month period.		
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): 4,050 hrs of operation on NG (max) – 3.215 times the hrs on 0.05% S (max) FO. 1,260 hrs/yr on FO (max).		

B.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions: GE PG7241 FA	lb/hr 575	tons/year 2,518.5
5. Method of Compliance (limit to 60 characters): Monitoring and recordkeeping of nitrogen content of fuel.		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60.332 (a)(1)		

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation _1____ of _1____

1. Visible Emissions Subtype: VE20	
2. Basis for Allowable Opacity: [X] Rule [ ] Other	
3. Requested Allowable Opacity: Normal Conditions: 30 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: Opacity CEM	
5. Visible Emissions Comment (limit to 200 characters): FAC62-296.410(2)(B)1	

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	
2. Basis for Allowable Opacity: [ ] Rule [ ] Other	
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor _1___ of _4___

1. Parameter Code: EM	2. Pollutant(s): SO2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40CFR 60 Subpart GG – Monitor sulfur content of the fuel. 40 CFR 75.10 – Either CEM and exhaust flow or fuel analysis and fuel flow.	

Continuous Monitoring System: Continuous Monitor _2___ of _4___

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60 Subpart GG – Monitor the fuel consumption and water to fuel ratio while using water injection during fuel oil firing. Also must monitor the nitrogen content of the fuel. 40 CFR 75.10	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

<u>Continuous Monitoring System:</u> Continuous Monitor _3___ of _4___

1. Parameter Code: O2 or CO2	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 75.10 – either O2 or CO2 (a diluent gas) if a NOx CEM is installed.	

<u>Continuous Monitoring System:</u> Continuous Monitor _4___ of _4___

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 75.10	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[X] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[X] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[X] C	[ ] E	[ ] Unknown
4. Baseline Emissions:			
PM		lb/hour	tons/year
SO2		lb/hour	tons/year
NO2			tons/year
5. PSD Comment (limit to 200 characters):			

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

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID:___3____ [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID:___6____ [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID:___7____ [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID:___8____ [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID:___5____ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

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. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
14. Acid Rain Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] 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:________ [ ] Not Applicable

Attachment 1 - Area Map(s)

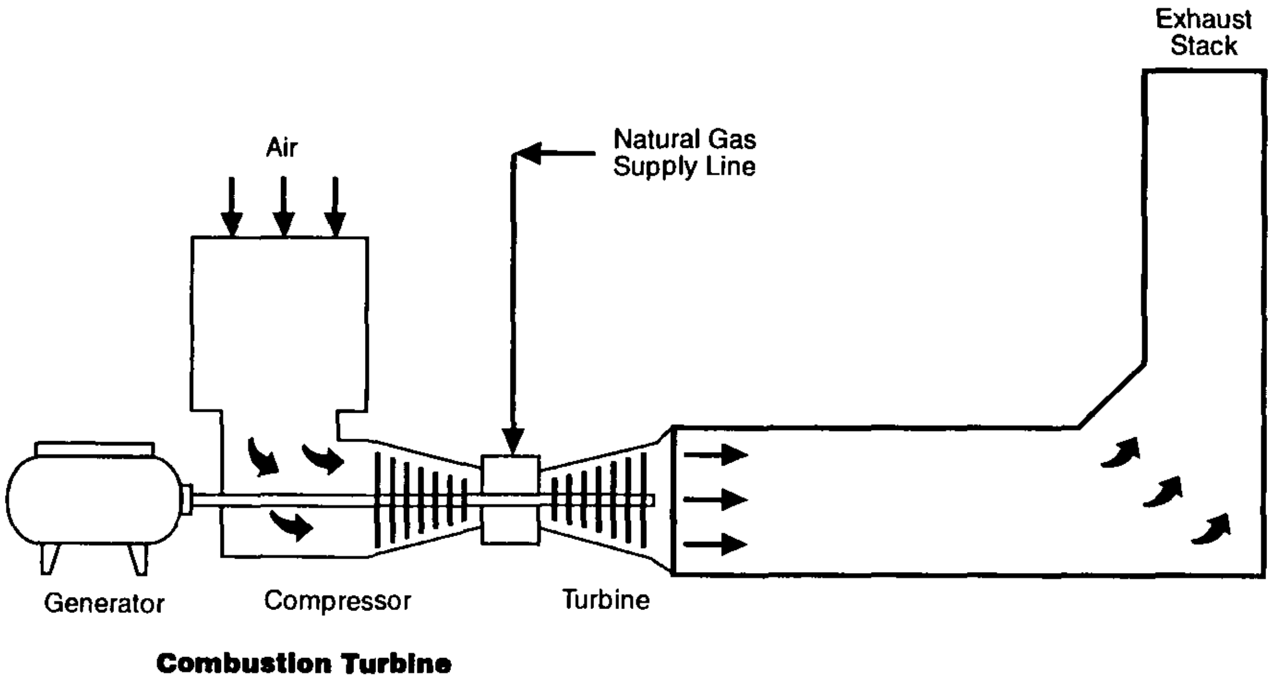
{Not scanned
Located in hard file}

Attachment 2 - Facility Plot Plan

{Not scanned
Located in Hard file}

Attachment 3 - Process Flow Diagram

Simple Cycle Combustion Turbine Process Flow Diagram



SIMPLE CYCLE COMBUSTION TURBINE

Attachment 4 - Fugitive Particulate Matter Control Plan

Precautions to Prevent Emissions of Unconfined Particulate Matter.

As a result of the construction of the simple cycle combustion turbine at the project site minimal quantities of unconfined particulate matter (fugitive dust) may be released to the atmosphere. These anticipated construction activities may be generally broken down into three phases as they relate to generating fugitive dust: debris removal, site preparation, and general construction. Because the combustion turbine is being installed at a preexisting site, material movement associated with debris removal and site preparation will be minimal. For the general construction phase of the project, JEA proposes to utilize watering to control fugitive dust. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder maintaining soil moisture content or establishing a crust which prevents soil movement under windy conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. For the construction phase of the project, it is proposed that water be applied as necessary during high wind conditions when fugitive dust is evident beyond the property boundary. The water will be applied using one or a combination of several methods listed above.

Attachment 5 - Supplemental Information for Construction Permit Application

BLACK & VEATCHLLP

MEMORANDUM

Jacksonville Electric Authority	B&V Project 29686
Kennedy CT	B&V File
Updated Baseline Emissions Calculations	09/14/98

To: Bert Gianazza, P.E.

From: M.J. Bareta

In reviewing the attached Table titled *K10 Fuel Usage and Emissions from August 1996 – July 1998,* it was noted that there are significant increases in recent usage of this boiler compared to the original 1995 – 1996 baseline. Based upon this new data, revised spreadsheets, based upon those used in the previous netting analysis and submitted to FDEP in the February 12, 1998 *Request for PSD Determination* (also attached) were prepared. These spreadsheets clearly show that based on the historic use of boiler KE10, and current vendor provided emissions data for the proposed replacement combustion turbine, over 4,050 hours of operation on natural gas, or 1,260 hours of operation are allowable without exceeding the PSD significant emissions threshold. Based on this data, the proposed project should continue to be classified as a minor source. Overall emissions will need to be limited in any twelve-month period to this operation. This can be demonstrated by accepting a permit condition limiting hours of operation to:

4,050 hours of operation on natural gas (max) – 3.125 * hours of operation on fuel oil.
1,260 hours of operation on 0.05% S fuel oil (max) in any twelve-month period.

Should you have any questions, please do not hesitate to call me.

K10 Fuel Usage and Emissions from August 1996 - July 1998

	1996					1997	1998							
	Aug	Sep	Oct	Nov	Dec	Jan - Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Annual Avg.
#6 Oil Burned (BBLS)	8,575.00	-	-	-	6,939.00	14,768.00	-	-	-	-	11,585.00	72,439.00	65,524.00	89,915.00
%Sufur of Oil	0.98	N/A	N/A	N/A	0.91	0.98	N/A	N/A	N/A	N/A	0.98	0.82	0.94	N/A
Natural Gas Burned (KCF)	95,799.00	39,830.00	339.00	-	1,290.00	210,554.00	-	-	-	-	7,300.00	21,259.00	104,965.00	240,668.00
Btu/BBL	6,397,985.00	N/A	N/A	N/A	6,369,095.00	6,406,340.00	N/A	N/A	N/A	N/A	6,415,108.00	6,317,118.00	6,361,171.00	N/A
Btu/FT3	1,046.00	1,052.00	1,052.00	N/A	1,290.00	1,055.00	N/A	N/A	N/A	N/A	1,057.00	1,066.00	1,047.00	N/A
MBtu from Oil	54,862.72	-	-	-	44,195.15	94,608.83	-	-	-	-	74,319.03	457,605.71	416,809.37	571,200.40
MBtu from Gas	100,205.75	41,901.16	356.63	-	1,664.10	222,134.47	-	-	-	-	7,716.10	22,662.09	109,898.36	253,269.33
MBtu Total	155,068.48	41,901.16	356.63	-	45,859.25	316,743.30	-	-	-	-	82,035.13	480,267.80	526,707.72	824,469.73
NOx from Oil (tons)	12.94	N/A	N/A	N/A	10.42	22.31	N/A	N/A	N/A	N/A	17.52	107.89	98.27	134.67
NOx from Gas (tons)	10.62	4.44	0.04	N/A	0.18	23.54	N/A	N/A	N/A	N/A	0.82	2.40	11.64	26.83
NOx Total (tons)	23.55	4.44	0.04	N/A	10.60	45.84	N/A	N/A	N/A	N/A	18.34	110.29	109.92	161.51
SOx from Oil (tons)	27.71	N/A	N/A	N/A	20.82	47.72	N/A	N/A	N/A	N/A	37.43	195.84	203.07	266.29
PM from Oil (tons)	2.20	N/A	N/A	N/A	1.69	3.79	N/A	N/A	N/A	N/A	2.97	16.36	16.32	21.67

Emission Factors:

	#6Oil	Natural Gas
NOx	0.47155 lbs/MBtu	0.119 lbs/MBtu
SOx	157*S lbs/Kgal	N/A
PM	(9.19*S + 3.22) lbs/Kgal	N/A

Prepared by Anthony Wilson 8/21/98

Attachment 1

PSD Netting Analysis Summaries

GE PG7241(FA)

	Combustion Turbine Potential Emissions (ton/year)	Revised KE10 Average Emissions, 1996-98 (ton/year)	Net Emission Increase (ton/year)	PSD Signifcant Emission Rate (ton/year)	PSD Significant?
NOx	200.48	161.51	38.97	40	No
CO	97.20	14.51	82.69	100	No
VOC	5.67	1.61	4.06	40	No
SO2	61.74	266.29	-204.55	40	No
PM10 Front Half	18.23	21.67	-3.45	15	No
Lead	0.07	2.89E-03	0.06	0.6	No
H2SO4	6.30	11.87	-5.57	7	No

NOTE: Combustion turbine emissions have been calculated based on the proposed operational limitations.

GE PG7241(FA) Potential Emissions

Potential emissions have been calculated based on the proposed operational limitations. For each pollutant, the range of operational scenarios was examined, and the scenario producing the highest annual emission rate is presented below for each pollutant.

Hourly emission rates reflect base load operation.

	Combustion Turbine Emissions [GE PG7241(FA)]									Allowable Emissions		
	Natural Gas Firing				Fuel Oil Firing				Total Emissions (ton/yr)	KE10 Average 95-96 Emissions (ton/yr)	PSD Significant Emission Rate (ton/yr)	Allowable CT Emission Rate (ton/yr)
	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)				
NOx	99.00	GE Data	4050	200.48	318	GE Data	0	0.00	200.48	161.50	40	201.50
CO	48	GE Data	4050	97.20	97	GE Data	0	0.00	97 20	14.51	100	114 51
VOC	2.8	GE Data	4050	5.67	7.5	GE Data	0	0.00	5.67	1.61	40	41.61
SO2	9.74	Note 1	0	0.00	98	GE Data	1260	61.74	61.74	266.88	40	306.88
PM10	9	GE Data	4050	18.23	17	GE Data	0	0.00	18.23	21.67	15	36.67
Lead	4.18E-04	Note 2	0	0.00	0.10629	AP-42 Table 3.1-4	1260	0.07	0.07	2.89E-03	0.6	0.60
H2SO4 Mist					10	GE Data	1260	6.30	6.30	11.87	7	18.87

NOTES:

1) Based upon AP-42 Table 3.1-1 emission factor, 0.006 lb/mmBtu, and maximum heat input as reported by G.E.

2) Based upon AP-42 Table 1.4-5 emission factor, 1050 Btu/SCF fuel heating value, and base load heat input as reported by G.E.

Jacksonville Electric Authority -- Kennedy Generating Station
KE10 Emissions Calculations

Natural Gas Firing

	Emission Factor				Ann. avg. last 2 years					
	Value		Reference	Justification	Fuel Use (M ft3)	Fuel Heating Value (Btu/SCF)	Emissions (ton/year)	Fuel Use (M ft3)	Fuel Heating Value (Btu/SCF)	Emissions (ton/year)
NOx	0.2119	lb / MBtu	Note 1	Note 2	240.7	1052	26 83	0	0	0.0000
CO	40	lb / M ft3	Note 3, 4	Standard referenc	240.7	1052	5 06	0	0	0.0000
VOC	1.411	lb / M ft3	Note 4, 5	Standard referenc	240.7	1052	0 18	0	0	0.0000
SO2	0.6	lb / M ft3	Note 3, 4	Standard referenc	240.7	1052	0.08	0	0	0.0000
PM10 Front Half	5	lb / M ft3	Note 4, 6	Standard referenc	240.7	1052	0 63	0	0	0.0000
Lead	2.71E-04	lb / M ft3	Note 4, 7	Standard referenc	240.7	1052	3 43E-05	0	0	0
H2SO4										

Fuel Oil Firing

	Emission Factor				Ann. Avg. last 2 years							
			Reference	Justification	Fuel Use (kgal)	Fuel Sulfur Content, S (%)	Fuel Heating Value (Btu/gal)	Emissions (ton/year)	Fuel Use (kgal)	Fuel Sulfur Content, S (%)	Fuel Heating Value (Btu/gal)	Emissions (ton/year)
NOx	0.47155	lb/MBtu	Note 1	Note 9	3776.4		151250	134.67	0			0.0000
CO	5	lb/kgal	AP-42, Table 1.3-1	Standard referenc	3776.4			9.44	0			0.0000
VOC	0.76	lb/kgal	AP-42, Table 1.3-2	Standard referenc	3776.4			1.44	0			0.0000
SO2	157*S	lb/kgal	AP-42, Table 1.3-1	Standard referenc	3776.4	0.9		266.80	0			0.0000
PM10 Front Half	9.19*S+3.22	lb/kgal	AP-42, Table 1.3-1	Standard referenc	3776.4	0.9		21.70	0			0.0000
Lead	1.51E-03	lb/kgal	AP-42, Table 1.3-1	Standard referenc	3776.4			2.85E-03	0			0.0000
H2SO4	6.983*S	lb/kgal	Note 8	Standard referenc	3776.4	0.9		11.87	0			0.0000

Total Emissions

	Annual Average Emissions (ton/year)		
NOx	161.4984	0.0000	
CO	14.5053	0.0000	
VOC	1.6137	0.0000	
SO2	266.8786	0 0000	
PM10 Front Half	22.3303	0 0000	
Lead	0.0029	0 0000	
H2SO4	11.8668	0 0000	

NOTES

1) Stack test data for KE10 dated 12/94
2) Of available data, the stack test results shown are believed to provide the most accurate estimate of unit emissions, note that this emission factor is lower than the AP-42 factor of ~0.55 lb/MBtu
3) AP-42, Table 1 4-1.
4) Factor shown is based on natural gas heating value of 1000 Btu/SCF; for emission calculations, factor is ratioed to reflect actual heating value shown
5) AP-42, Table 1 4-3
6) AP-42, Table 1.4-2
7) AP-42, Table 1.4-5
8) H2SO4 emissions from fuel oil combustion calculated as follows AP-42, Table 1.3-1 Factor used to estimate SO3 emissions All SO3 assumed to convert to H2SO4
9) Of available data, the stack test results shown are believed to provide the most accurate estimate of unit emissions, note that this emission factor is almost equal to the AP-42 factor of ~0.47 lb/MBtu

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

JEA POWER TO SERVE

February 12, 1998

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Request for PSD Determination

Dear Mr. Fancy:

On December 17, 1997, the Jacksonville Electric Authority (JEA) and Black & Veatch (JEA's air permitting consultant) met with the Florida Department of Environmental Protection (FDEP) to discuss air permitting issues associated with a potential new emission source. At the December 17 meeting, FDEP staff suggested that JEA submit information which would allow FDEP to make an official determination of Prevention of Significant Deterioration (PSD) applicability to this project. Therefore, this letter is submitted to FDEP to formally request such a determination.

JEA is proposing to install one simple cycle, 160 MW Frame F combustion turbine (CT) at the Kennedy Generating Station. This unit will be used primarily as a peaking unit, firing natural gas as its primary fuel and low sulfur distillate fuel oil as a backup fuel. Following the installation of the CT, the existing natural gas and residual oil-fired boiler KE10 will be taken out of service. Commensurate with PSD regulations and guidance, the determination of whether the proposed CT is a major modification to a major stationary source is based upon the potential emission increases from the new unit, combined with any contemporaneous increases or decreases in source emissions exceeding significant levels. Such a determination is often referred to as a "netting analysis". JEA has prepared a netting analysis in which past actual emissions from KE10 have been subtracted from the potential emission increases of the CT to determine the net emissions change. The assumptions and information used in this analysis are discussed in the following paragraphs.

Estimated CT Emission Increases

At this time, selection of a specific CT has yet to be completed. The range of choices has been narrowed to either a GE PG7241 FA or a Westinghouse 501F. Therefore, emissions from both of these CTs have been examined. In both cases, potential emissions of all PSD-regulated pollutants except lead have been calculated based on expected base load emissions data provided by the vendor. These data were developed based on ISO conditions (i.e., 59 F ambient temperature and 60% relative humidity). Lead emissions were based on AP-42 emission factors and the base load heat input rate.

The CT, once installed, will be used to supply peaking power. Therefore, JEA is proposing a reduced capacity factor for the CT. The proposed capacity factors, which are outlined in Table 1, would allow the project to "net out" of PSD review. As shown in the table, the specific limitations which would be imposed are dependent on the final turbine selection.

Table 1
Proposed Operational Limitations for Combustion Turbine

	Maximum Natural Gas Firing (hours/year)	Maximum #2 Fuel Oil Firing (hours/year)	Fuel Oil Sulfur Content
GE PG7241 (FA)	3120 - 3.25X *	960	0.05 wt%
Westinghouse 501F	1841 - 2.63X *	700	0.05 wt%

* X = hours of #2 fuel oil firing during the year

Contemporaneous Emission Decreases

Past actual KE10 emission estimates are presented in Table 2. These have been calculated based upon 1995 and 1996 operations. This satisfies PSD guidance, as these represent the two most recent available years of operational data which are representative of normal operation.

Table 2
Estimated Average KE10 Emissions During 1995-96

Pollutant	KE10 1995-96 Average Emissions (ton/year)
NO_x	115.9
CO	14.8
VOC	1.0
SO_2	128.2
PM_{10} (front half)	11.5
Lead	0.001
H_2SO_4	5.7

Emissions of the PSD-regulated pollutants (excluding NO_x) from residual oil and natural gas combustion were calculated using emission factors from Sections 1.3 and 1.4, respectively, of AP-42 (fifth edition, including supplements). Relevant operational data were taken from Steam-Electric Plant Operation and Design Reports for 1995 and 1996 operations, submitted to the U.S. Department of Energy. Emission calculations for a given year were based on actual fuel usage, weighted average heating values, and weighted average residual oil sulfur content for that year, as reported on the Operation and Design Reports. SO_2 emissions from natural gas combustion were based on an average sulfur content of 2000 grains/10^6 SCF, as suggested by AP-42, Section 1.4. H_2SO_4 emissions from residual oil combustion have been estimated using the emission factor for SO_3 emissions (taken from AP-42 Section 1.3), and assuming that all SO_3 is eventually converted to H_2SO_4.

The NO_x emission factors for fuel oil firing and natural gas firing were obtained from stack testing data. Several stack tests were reviewed to determine which provided the most realistic and time-representative information. Isolated tests were performed on the unit in the early nineties at part-load operations. Testing was again performed at numerous loads for both oil and gas firing in December 1994. This testing was part of the Acid Rain Part 75 certification tests. Because the 1994 testing represents the most recent and comprehensive testing at all loads, the emission factors derived from the testing were utilized to calculate NO_x emissions for KE10.

The December 1994 stack test data are believed to provide a good representation of KE10 NO_x emissions during steady state operation. However, these data do not account for unsteady state operations such as startup, shutdown, load changes and malfunctions. Due largely to the age of the unit, KE10 air emissions are thought to be much higher during these conditions than during steady-state operation. Furthermore, the time required to bring the unit and its associated emissions to steady state conditions following an unsteady state event is greater than would be expected with a newer unit. Since KE10 has been operated primarily as a peaking unit over the past several years, unsteady state operations occurred more often than would be expected with a baseload unit. As the December 1994 stack test results do not take into account unsteady state operation, annual emission estimates based on the stack testing are believed to be conservatively low.

In addition, while the December 1994 stack test data do suggest slightly higher NO_x emissions from residual oil combustion than AP-42 (0.472 lb/10^6 Btu from the testing versus ~0.441 lb/10^6 Btu from AP-42 Section 1.3 for normal firing), the NO_x emission rate derived from the stack tests during natural gas firing is less than the appropriate AP-42 emission factor by 0.31 lb/10^6 Btu. Consequently, the stack test results lead to annual emission estimates which are notably lower than if AP-42 factors were used.

Since the NO_x emission estimates are believed to be of a conservative nature, and the magnitude of annual NO_x emissions is relatively low, the JEA proposes that the NO_x emissions calculation approach described above be used to determine baseline NOx emissions.

Attachment 1 outlines the net emission calculations for this project, considering both the GE and Westinghouse CTs. Based upon the assumptions and operational limits proposed above, the data presented in Attachment 1 demonstrate that the proposed project will not trigger PSD review. Attachment 2 contains detailed spreadsheet calculations which support the values reported in Attachment 1.

If you have any questions on this issue, please contact me at (904) 632-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Health & Safety Group

Enclosures

cc: Amy Carlson, Black & Veatch
Marty Costello, FDEP

Attachment 1

PSD Netting Analysis Summaries

GE PG7241(FA)

	Combustion Turbine Potential Emissions (ton/year)	KE10 Average Emissions 1995-96 (ton/year)	Net Emission Increase (ton/year)	PSD Signifcant Emission Rate (ton/year)	PSD Significant?
NOx	154.560	115.940	38.620	40	No
CO	74.880	14.777	60.103	100	No
VOC	4.368	1.008	3.360	40	No
SO2	45.648	128.229	-82.581	40	No
PM10 Front Half	14.040	11.507	2.533	15	No
Lead	0.051	0.001	0.050	0.6	No
H2SO4	4.800	5.696	-0.896	7	No

Westinghouse 501F

	Combustion Turbine Potential Emissions (ton/year)	KE10 Average Emissions 1995-96 (ton/year)	Net Emission Increase (ton/year)	PSD Signifcant Emission Rate (ton/year)	PSD Significant?
NOx	154.000	115.940	38.060	40	No
CO	75.481	14.777	60.704	100	No
VOC	6.650	1.008	5.642	40	No
SO2	31.150	128.229	-97.079	40	No
PM10 Front Half	24.624	11.507	13.117	15	No
Lead	0.033	0.001	0.031	0.6	No
H2SO4	3.271	5.696	-2.425	7	No

NOTE: Combustion turbine emissions have been calculated based on the proposed operational limitations.

GE PG7241(FA) Potential Emissions

Potential emissions have been calculated based on the proposed operational limitations. For each pollutant, the range of operational scenarios was examined, and the scenario producing the highest annual emission rate is presented below for each pollutant.

Hourly emission rates reflect base load operation.

	Combustion Turbine Emissions (GE PG7241(FA))									Allowable Emissions		
	Natural Gas Firing				Fuel Oil Firing				Total Emissions (ton/yr)	KE10	PSD Significant Emission Rate (ton/yr)	Allowable CT Emission Rate (ton/yr)
	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)		Average 95-96 Emissions (ton/yr)		
NOx	99.00	GE Data	0	0	322	GE Data	960	154.56	154.56	115.9396	40	155.9396
CO	48	GE Data	3120	74.88	97	GE Data	0	0	74.88	14.7773	100	114.7773
VOC	2.8	GE Data	3120	4.368	7.5	GE Data	0	0	4.368	1.0078	40	41.0078
SO2	22.8603	Note 1	0	0.0000	95.1	GE Data	960	45.648	45.6480	128.2288	40	168.2288
PM10	9	GE Data	3120	14.04	17	GE Data	0	0	14.04	11.5072	15	26.5072
Lead	4.18E-04	Note 2	0	0.0000	0.10629	AP-42 Table 3.1-4	960	0.0510	0.0510	0.0013	0.6	0.6013
H2SO4 Mist					10	GE Data	960	4.8	4.8	5.6962	7	12.6962

NOTES:
1) Based upon AP-42 Table 3.1-1 emission factor, 0.015 wt% sulfur in fuel, and maximum heat input as reported by G.E.
2) Based upon AP-42 Table 1.4-5 emission factor, 1050 Btu/SCF fuel heating value, and base load heat input as reported by G.E.

Westinghouse 501F Potential Emissions

Potential emissions have been calculated based on the proposed operational limitations. For each pollutant, the range of operational scenarios was examined, and the scenario producing the highest annual emission rate is presented below for each pollutant.

Hourly emission rates reflect base load operation.

	Combustion Turbine Emissions									Allowable Emissions		
	Natural Gas Firing				Fuel Oil Firing				Total Emissions (ton/yr)	KE10 Average 95-96 Emissions (ton/yr)	PSD Significant Emission Rate (ton/yr)	Allowable CT Emission Rate (ton/yr)
	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)				
NOx	167.00	Westinghouse data	0	0.0000	440	Westinghouse data	700	154	154.0000	115.9396	40	155.9396
CO	82	Westinghouse data	1841	75.4810	166	Westinghouse data	0	0	75.4810	14.7773	100	114.7773
VOC	7	Westinghouse data	0	0.0000	19	Westinghouse data	700	6.65	6.6500	1.0078	40	41.0078
SO2	20	Note 1	0	0.0000	89	Westinghouse data	700	31.15	31.1500	128.2288	40	168.2288
PM10	19	Westinghouse data	0	0.0000	70.355	Note 3	700	24.62425	24.6243	11.5072	15	26.5072
Lead	4.19E-04	Note 2	0	0	0.093032	AP-42 Table 3.1-4	700	0.0325612	0.0326	0.0013	0.6	0.6013
H2SO4 Mist					9.345	Note 4	700	3.27075	3.2708	5.6962	7	12.6962

NOTES:
1) Emission rate reflects 10 times the rate predicted by vendor data.
2) Based upon AP-42 Table 1.4-5 emission factor, 1050 Btu/SCF fuel heating value, and base load heat input (LHV).
3) Reflects Westinghouse data for front + back half PM, less estimated H2SO4 emission rate.
4) Estimated from available vendor data as follows: ratio of H2SO4/SO2 mass emission rates for GE turbine used to estimate H2SO4 emissions from Westinghouse turbine by muliplying SO2 mass emission rate for Westinghouse turbine by the GE turbine ratio.

Jacksonville Electric Authority – Kennedy Generating Station
KE10 Emissions Calculations

Natural Gas Firing

	Emission Factor				1995			1996		
	Value		Reference	Justification	Fuel Use (M ft3)	Fuel Heating Value (Btu/SCF)	Emissions (ton/year)	Fuel Use (M ft3)	Fuel Heating Value (Btu/SCF)	Emissions (ton/year)
NOx	0.2119	lb / MMBtu	Note 1	Note 2	688.0	1040	74.0400	344.4	1051	38.3601
CO	40	lb / M ft3	Note 3, 4	Standard reference	688.0	1040	13.8782	344.4	1051	7.2303
VOC	1.411	lb / M ft3	Note 4, 5	Standard reference	[illegible]	1040	0.4831	344.4	1051	0.2554
SO2	0.6	lb / M ft3	Note 3, 4	Standard reference	[illegible]	1040	0.2067	344.4	1051	0.1086
PM10 Front Half	5	lb / M ft3	Note 4, 6	Standard reference	[illegible]	1040	1.7473	344.4	1051	0.9048
Lead	2.71E-04	lb / M ft3	Note 4, 7	Standard reference	688.0	1040	9.47E-05	344.4	1051	4.905E-05
H2SO4	[illegible]									

Fuel Oil Firing

	Emission Factor				1995				1996			
			Reference	Justification	Fuel Use (kgal)	Fuel Sulfur Content, S (%)	Fuel Heating Value (Btu/gal)	Emissions (ton/year)	Fuel Use (kgal)	Fuel Sulfur Content, S (%)	Fuel Heating Value (Btu/gal)	Emissions (ton/year)
NOx	0.47188	lb/MMBtu	Note 1	Note 9	184.0		151000	6.0171	3150		151004	112.0824
CO	5	lb/kgal	AP-42, Table 1.3-1	Standard reference	184.0			0.4820	3150			7.0750
VOC	0.76	lb/kgal	AP-42, Table 1.3-2	Standard reference	184.0			0.0702	3150			1.1970
SO2	157*S	lb/kgal	AP-42, Table 1.3-1	Standard reference	184.0	0.900		14.0671	3150	0.079		242.0822
PM10 Front Half	9.19*S+3.22	lb/kgal	AP-42, Table 1.3-1	Standard reference	184.0	0.900		1.1264	3150	0.079		19.2416
Lead	1.51E-03	lb/kgal	AP-42, Table 1.3-10	Standard reference	184.0			0.0001	3150			0.0024
H2SO4	0.963*S	lb/kgal	Note 8	Standard reference	184.0	0.900		0.0252	3150	0.079		10.7673

Total Emissions

	1995	1996	95-96 Average
	Emissions (ton/year)	Emissions (ton/year)	Emissions (ton/year)
NOx	00.0000	151.2125	115.8300
CO	14.4402	15.1143	14.7773
VOC	0.5033	1.4524	1.0079
SO2	14.2000	242.1900	128.2204
PM10 Front Half	2.0070	20.1467	11.8072
Lead	0.0002	0.0024	0.0013
H2SO4	0.0252	10.7673	5.0062

NOTES
1) Stack test data for KE 10 dated 10/94
2) Of available data, the stack test results shown are believed to provide the most accurate estimate of unit emissions; note that the emission factor is lower than the AP-42 factor of ~0.55 lb/MMBtu
3) AP-42, Table 1.4-1
4) Factor shown is based on natural gas heating value of 1000 Btu/SCF; for emission calculations, factor is ratioed to reflect actual heating value shown
5) AP-42, Table 1.4-3
6) AP-42, Table 1.4-2
7) AP-42, Table 1.4-4
8) H2SO4 emissions from fuel oil combustion calculated as follows: AP-42, Table 1.3-1 Factor used to estimate SO3 emissions. All SO3 assumed to convert to H2SO4
9) Of available data, the stack test results shown are believed to provide the most accurate estimate of unit emissions; note that the emission factor is almost equal to the AP-42 factor of ~0.47 lb/MMBtu

TECHNICAL PROPOSAL DATA

1.5 EQUIPMENT AND MATERIAL DATA. The information required on the following pages is to assist the Engineer in evaluating the Technical Proposal.

The data listed herein is stated for definitive purposes and for the convenience of the Engineer and the Owner.

General Electric Company
(Bidder's Name)

1.5.1 Performance Data - Combustion Turbine Generators.

Performance Data at Specified Conditions (Reference Table 2.1-1)

Parameter	Condition A	Condition B
Guaranteed or expected	Guaranteed	Guaranteed
Gross generator output, kW	173,200	182,000
CTG auxiliary power, kW	608	1542
CTG heat consumption, LHV, MBtu/h	1622.9	1821.8
Net CTG output, kW*	172590	180460
Net CTG heat rate, LHV, Btu/kWh*	9370	10010
Fuel flow, lbm/h	78496	98210
Water injection flow, lbm/h	0	119690
Turbine inlet temperature °F	Proprietary	Proprietary
Inlet airflow, lbm/h	3,423,600	3,423,600
Inlet air pressure drop, in. H_2O	3.04	3.04
Compressor inlet temperature, °F	59	59
Exhaust pressure drop, in. H_2O	5.5	5.5
Exhaust gas flow, lbm/h	3542×10^3	3683×10^3
NO_x emissions at 15 percent O_2, ppmvd*	15	42
NO_x emissions at 15 percent O_2, lbm/h*	99	318
CO emissions ppmvd*	15	20
CO emissions lbm/h*	48	65

UHC emissions, ppmvw*	7	7
UHC emissions, lbm/h*	14	15
VOC emissions, ppmvw*	1.4	3.5
VOC emissions, lbm/h*	2.8	7.5
TSP, lbm/h*(non-condensables only)	9	17
PM10, lbm/h*(non-condensables only)	9	17
TSP, lbm/h*(excluding H_2SO_4, Including other condensables)	19	46
PM10, lbm/h*(excluding H_2SO_4, Including other condensables)	19	46
Opacity, percent*	5	20
SO_2, ppmvw, lbm/h*	0.0	93
H_2SO_4, lbm/h*		

Note: The basis for each load condition is specified in the Technical Requirements, Subsection 2.1, Performance Criteria. Items marked with an asterisk (*) shall be guaranteed for all load conditions designated "Guaranteed," in accordance with Subsection 2.1.

1.5.2 General Data - Combustion Turbine.

Manufacturer	GE
Location assembled	Greenville, SC
Combustion turbine model number	PG 7241 FA

1.5.3 Supplemental Performance Data. The following three-page table, designated C.5, shall be reproduced by the bidder as required to define the requested information for the following ambient temperatures and coincident relative humidities:

Temperature/Relative Humidity Points:	20° F/60 percent
	59° F/60 percent
	95° F/60 percent

Numbering sequence of the tables shall be as follows:

Table No.	Fuel	Ambient Conditions
1.5-1	Natural gas	20° F/60 percent RH
1.5-2	Natural gas	59° F/60 percent RH
1.5-3	Natural gas	95° F/60 percent RH
1.5-4	Fuel Oil	20°F/60 percent RH
1.5-5	Fuel Oil	59°F/60 percent RH
1.5.6	Fuel Oil	95°F/60 percent RH

Minimum load shall be defined as the minimum load at which the base load NO_x emission concentrations are maintained.

TABLE 1.5 - 1

Ambient Temperature/
Relative Humidity: 20 °F/ 60 percent
GE

Manufacturer:

Barometric Pressure: 14.69 psia
FA

Model No./Combustor: PG 7241

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ___Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	14900	46600	93200	139900	186500
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	35375	15650	11520	9950	9310
Exhaust flow, lb/h	2714×10^3	2725×10^3	2741×10^3	3025×10^3	3800×10^3
Exhaust Temp., °F	647	787	1017	1112	1081
Inlet guide vane position, degrees	54	54	54	60.4	88
Fuel flow, lb/h	25495	35274	51932	67327	83980
Water injection flow lb/h	--------	--------------	-------------	--------------	---------------
Nitrogen oxides, ppmvd at 15 percent O_2	69	93	94	15	15
Nitrogen oxides, lb/h as NO_2	137	266	401	84	105
Carbon monoxide, ppmvd	102	102	699	15	15
Carbon monoxide, lb/h	261	259	1759	41	52
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

Unburned hydrocarbon, ppmvw	128	25	182	7	7
Unburned hydrocarbon, lb/h	193	38	279	12	15
Volatile organic compounds, ppmvw	25.6	5	36.4	1.4	1.4
Volatile organic compounds, lb/h	38.6	7.6	55.8	2.4	3
Oxygen, vol %	17.54	16.11	13.85	12.57	12.54
Nitrogen, vol %	76.75	76.25	75.45	75	74.99
Carbon, vol %	1.59	2.25	3.3	3.89	3.9
Argon, vol %	.92	.91	.9	.89	.91
Water, vol %	3.21	4.49	6.5	7.65	7.67
Opacity, percent	5	5	5	5	5

TABLE 1.5 - 2

Ambient Temperature/
Relative Humidity: 59 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ____ Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	13900	43300	86600	129900	173200
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	36505	16080	11790	10120	9370
Exhaust flow, lb/h	2570×10^3	2580×10^3	2595×10^3	2890×10^3	3542×10^3
Exhaust Temp., °F	690	830	1060	1139	1116
Inlet guide vane position, degrees	54	54	54	61.8	88
Fuel flow, lb/h	24542	33678	49383	63584	78495
Water injection flow lb/h	-----	-----	-----	-----	-----
Nitrogen oxides, ppmvd at 15 percent O_2	67	59	89	15	15
Nitrogen oxides, lb/h as NO_2	127	161	361	79	99
Carbon monoxide, ppmvd	102	> 1000	647	15	15
Carbon monoxide, lb/h	246	2596	1533	39	48
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

Unburned hydrocarbon, ppmvw	103	479	145	7	7
Unburned hydrocarbon, lb/h	148	691	211	11	14
Volatile organic compounds, ppmvw	20.6	95.8	29	1.4	1.4
Volatile organic compounds, lb/h	29.6	138.2	42.2	2.2	2.8
Oxygen, vol %	17.34	15.92	13.68	12.51	12.38
Nitrogen, vol %	76.12	75.62	74.84	74.44	74.39
Carbon, vol %	1.6	2.26	3.3	3.84	3.9
Argon, vol %	.91	.91	.89	.9	.89
Water, vol %	4.03	5.29	7.29	8.32	8.44
Opacity, percent	5	5	5	5	5

TABLE 1.5 - 3

Ambient Temperature/
Relative Humidity: 95 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ______ Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	12000	37600	75200	112800	150400
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	40305	17360	12500	10690	9760
Exhaust flow, lb/h	2429×10^3	2438×10^3	2452×10^3	2691×10^3	3253×10^3
Exhaust Temp., °F	729	862	1078	1170	1144
Inlet guide vane position, degrees	54	54	54	61.6	88
Fuel flow, lb/h	23395	31570	45465	58321	70999
Water injection flow lb/h	-------	-------	--------	---------	-------
Nitrogen oxides, ppmvd at 15 percent O_2	53	45	65	15	15
Nitrogen oxides, lb/h as NO_2	97	115	243	73	89
Carbon monoxide, ppmvd	102	>1000	687	15	15
Carbon monoxide, lb/h	229	2129	1515	36	43
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	[illegible]	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

Unburned hydrocarbon, ppmvw	87	422	172	7	7
Unburned hydrocarbon, lb/h	118	581	239	11	13
Volatile organic compounds, ppmvw	17.4	84.4	34.4	1.4	1.4
Volatile organic compounds, lb/h	23.6	116.2	47.8	2.2	2.6
Oxygen, vol %	16.85	15.53	13.44	12.24	12.1
Nitrogen, vol %	74.33	73.88	73.17	72.76	72.71
Carbon, vol %	1.61	2.22	3.19	3.75	3.82
Argon, vol %	.89	.89	.87	.86	.87
Water, vol %	6.33	7.49	9.83	10.39	10.51
Opacity, percent	5	5	5	5	5

TABLE 1.5 - 4

Ambient Temperature/
Relative Humidity: 20 °F/ 60 percent
GE

Manufacturer:

Barometric Pressure: 14.69 psia
FA

Model No./Combustor: PG 7241

Natural Gas: LHV = ______ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low No_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	15200	47600	95200	142900	190500
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	34960	15590	12030	10480	10000
Exhaust flow, lb/h	$2717x10^3$	$2729x10^3$	$2806x10^3$	$3156x10^3$	$3947x10^3$
Exhaust Temp., °F	655	803	995	1058	1045
Inlet guide vane position, degrees	54	54	54	61.1	88
Fuel flow, lb/h	28646	40005	61741	80733	102695
Water injection flow lb/h	0	0	54260	87910	125980
Nitrogen oxides, ppmvd at 15 percent O_2	72	112	42	42	42
Nitrogen oxides, lb/h as NO_2	148	333	196	259	332
Carbon monoxide, ppmvd	>1000	428	124	38	20
Carbon monoxide, lb/h	2242	1096	315	108	70
Sulfur dioxide, ppmw	5	6	9	11	11
Sulfur dioxide, lb/h	27	38	59	77	98
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

Unburned hydrocarbon, ppmvw	157	52	14	7	7
Unburned hydrocarbon, lb/h	235	78	22	13	16
Volatile organic compounds, ppmvw	78.5	26	7	3.5	3.5
Volatile organic compounds, lb/h	117.5	39	11	6.5	8
Oxygen, vol %	17.65	16.22	13.24	11.78	11.45
Nitrogen, vol %	77.16	76.83	73.86	72.53	71.99
Carbon, vol %	2.1	3.01	4.49	5.24	5.36
Argon, vol %	.93	.92	.88	.86	.86
Water, vol %	2.17	3.03	7.53	9.59	10.35
Opacity, percent	20	20	20	20	20

TABLE 1.5 - 5

Ambient Temperature/
Relative Humidity: 59 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low No_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	14600	45500	91000	136500	182000
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	35280	15790	12200	10800	10010
Exhaust flow, lb/h	2573×10^3	2585×10^3	2658×10^3	2820×10^3	3683×10^3
Exhaust Temp., °F	700	852	1050	1191	1098
Inlet guide vane position, degrees	54	54	54	56.7	88
Fuel flow, lb/h	27768	38728	59849	79472	98210
Water injection flow lb/h	0	0	51810	89620	119690
Nitrogen oxides, ppmvd at 15 percent O_2	70	109	42	42	42
Nitrogen oxides, lb/h as NO_2	138	314	190	255	318
Carbon monoxide, ppmvd	> 1000	384	91	20	20
Carbon monoxide, lb/h	1910	925	217	49	65
Sulfur dioxide, ppmw	5	6	10	12	11
Sulfur dioxide, lb/h	26	37	57	75	93
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

Unburned hydrocarbon, ppmvw	134	44	12	7	7
Unburned hydrocarbon, lb/h	191	63	17	11	15
Volatile organic compounds, ppmvw	67	22	6	3.5	3.5
Volatile organic compounds, lb/h	95.5	31.5	8.5	5.5	7.5
Oxygen, vol %	17.43	15.97	12.94	10.71	11.09
Nitrogen, vol %	76.53	76.19	73.22	71.3	71.3
Carbon, vol %	2.13	3.06	4.58	5.74	5.48
Argon, vol %	.92	.92	.88	.85	.86
Water, vol %	2.99	3.87	8.39	11.41	11.28
Opacity, percent	20	20	20	20	20

TABLE 1.5 - 6

Ambient Temperature/
Relative Humidity: 95 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ______ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	12800	40000	80000	120100	160100
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	38490	16900	12770	11150	10240
Exhaust flow, lb/h	2432×10^3	2443×10^3	2501×10^3	2681×10^3	3365×10^3
Exhaust Temp., °F	740	886	1084	1200	1133
Inlet guide vane position, degrees	54	54	54	58.3	88
Fuel flow, lb/h	26561	36442	55072	72189	88377
Water injection flow lb/h	0	0	38960	68390	93580
Nitrogen oxides, ppmvd at 15 percent O_2	55	84	42	42	42
Nitrogen oxides, lb/h as NO_2	104	228	175	231	286
Carbon monoxide, ppmvd	731	372	87	20	20
Carbon monoxide, lb/h	1649	835	193	47	59
Sulfur dioxide, ppmw	5	6	9	12	11
Sulfur dioxide, lb/h	25	35	52	69	84
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

Unburned hydrocarbon, ppmvw	119	42	11	7	7
Unburned hydrocarbon, lb/h	162	57	16	11	13
Volatile organic compounds, ppmvw	59.5	21	5.5	3.5	3.5
Volatile organic compounds, lb/h	81	28.5	8	5.5	6.5
Oxygen, vol %	16.93	15.55	12.8	10.91	10.97
Nitrogen, vol %	74.73	74.42	72.03	70.5	70.25
Carbon, vol %	2.14	3.02	4.45	5.46	5.37
Argon, vol %	.9	.89	.86	.83	.84
Water, vol %	5.3	6.12	9.86	12.3	12.57
Opacity, percent	20	20	20	20	20

General Electric Model PG7241(FA) Gas Turbine
Jacksonville Electric Authority

Estimated Performance - Configuration: DLN Combustor

Compressor Inlet Conditions 59 F (15 C), 60% Relative Humidity

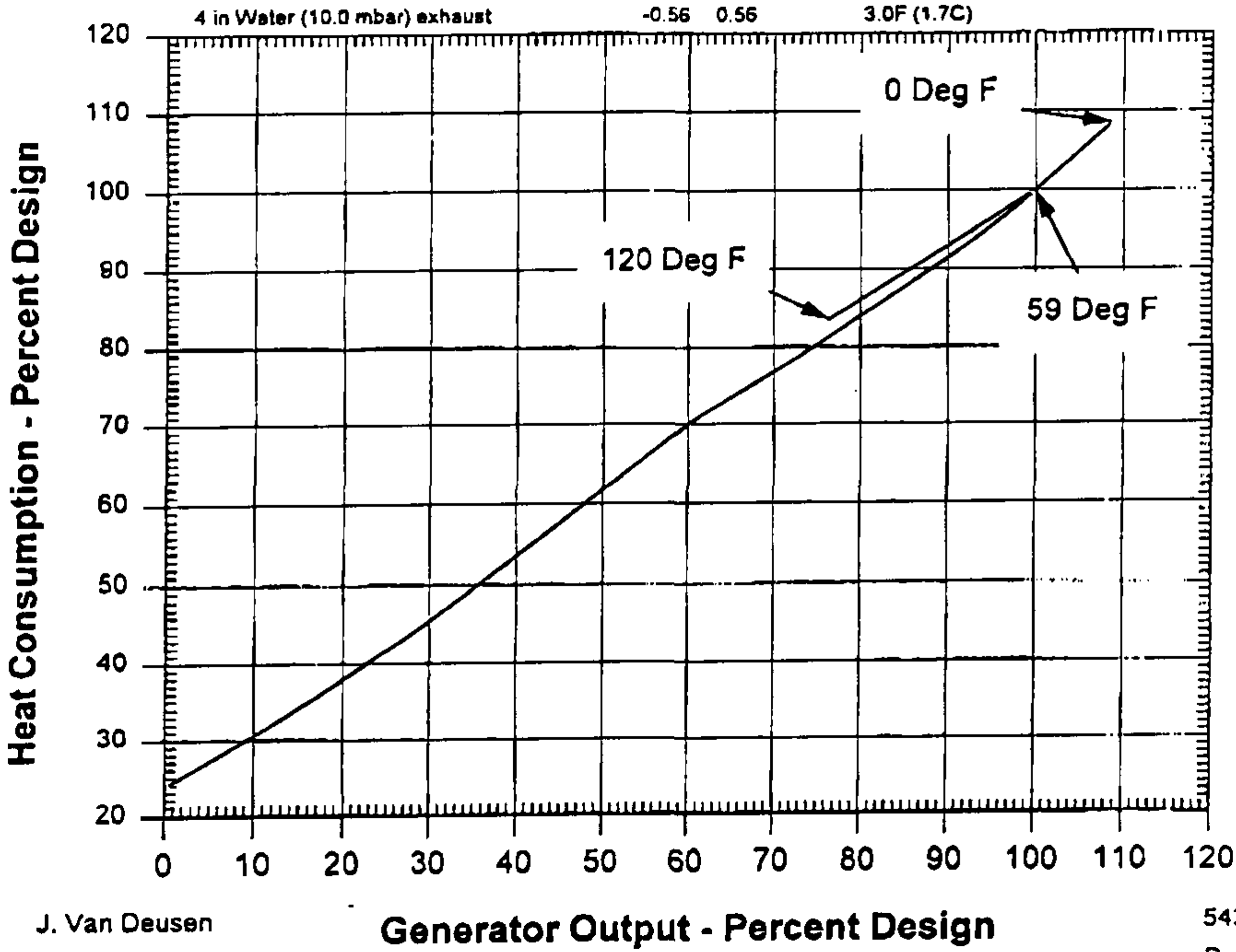
Atmospheric Pressure 14.7 psia (1.013 bar)

Fuel:			Customer Specified Gas
Design Output	kW		173200
Design Heat Rate (LHV)	Btu/kWh	(kJ/kWh)	~~9400 (9912)~~ 9570
Design Heat Cons (LHV)	Btu/h	(kJ/h)x10^6	1622.9 (1711.8)
Design Exhaust Flow	lb/h	(kg/h)x10^3	3542.0 (1607)
Exhaust Temperature	deg. F	(deg. C)	1116 (602.2)
Load			Base

Notes:

1. Altitude correction on curve 416HA662 Rev A.
2. Ambient temperature correction on curve 543HA873 Rev 0.
3. Effect of modulating IGV's on exhaust temperature and flow on curve 543HA874 Rev 0
4. Humidity effects on curve 498HA697 Rev. B - all performance calculated with 60% constant relative humidtiy.
5. Plant Performance is measured at the generator terminals and includes allowances for the effects of exitation power, shaft driven auxiliaries, and 3.04 in H2O (6.33 mbar) inlet and 5.5 in H2O (13.70 mbar) exhaust pressure drops and a DLN Combustor.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	% Effect on Heat Rate	Effect on Exhaust Temp.
4 in Water (10.0 mbar) inlet	-1.54	0.56	3.0F (1.7C)
4 in Water (10.0 mbar) exhaust	-0.56	0.56	3.0F (1.7C)



J. Van Deusen
5/18/98

543HA872
Rev - 0

General Electric Model PG7241(FA) Gas Turbine
Jacksonville Electric Authority

Estimated Performance - Configuration: DLN Combustor

Compressor Inlet Conditions 59 F (15 C), 60% Relative Humidity

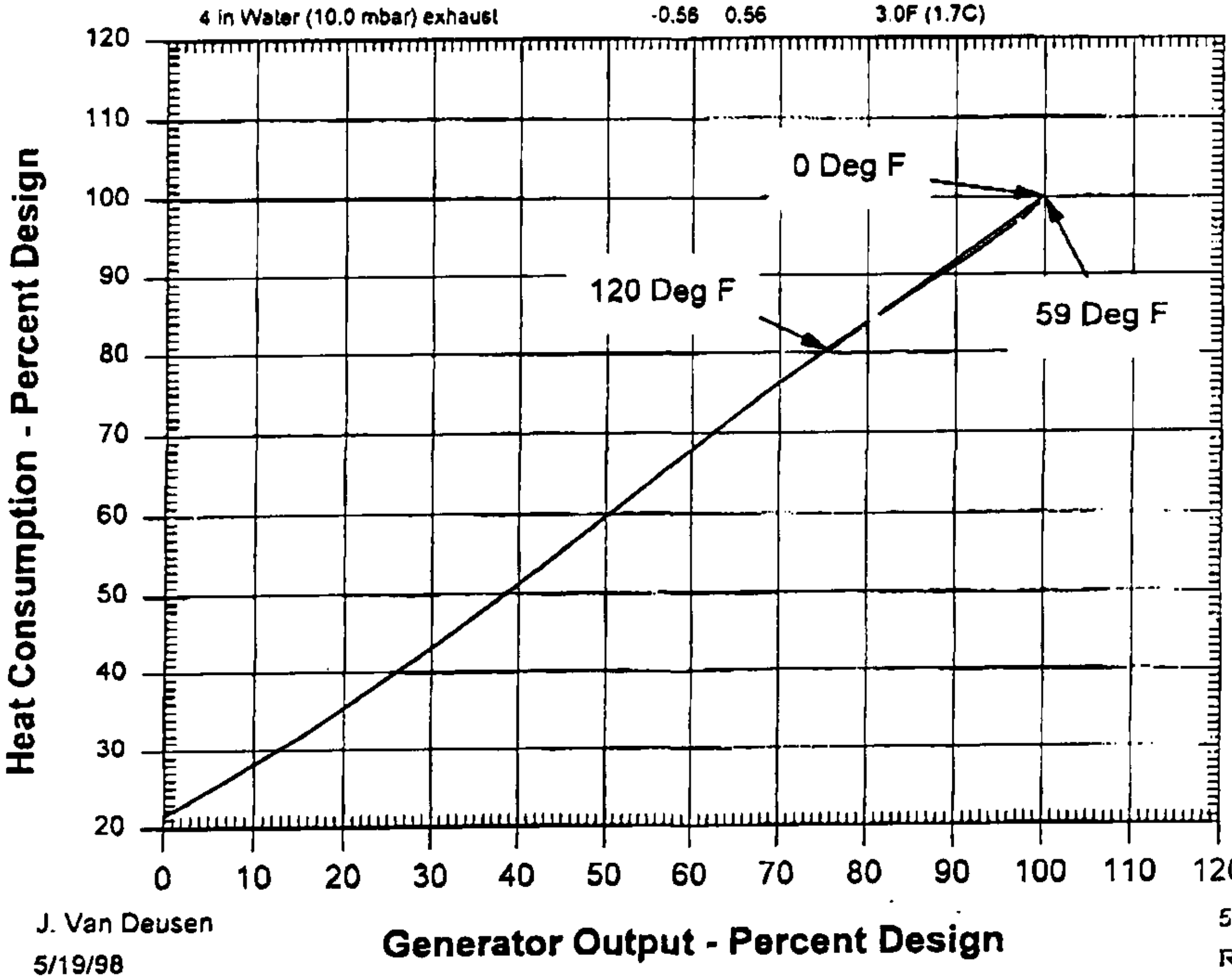
Atmospheric Pressure 14.7 psia (1.013 bar)

Fuel:			Distillate
Design Output	kW		182000
Design Heat Rate (LHV)	Btu/kWh	(kJ/kWh)	10100 (10650)
Design Heat Cons (LHV)	Btu/h	(kJ/h)x10^6	1821.8 (1921.7)
Design Exhaust Flow	lb/h	(kg/h)x10^3	3683.0 (1671)
Exhaust Temperature	deg. F	(deg. C)	1098 (592.2)
Design Water Flow	lb/h		119690
Load			Base

Notes:

1. Altitude correction on curve 416HA662 Rev A.
2. Ambient temperature correction on curve 543HA876 Rev 0.
3. Effect of modulating IGV's on exhaust temperature and flow on curve 543HA877 Rev 0.
4. Humidity effects on curve 498HA697 Rev. B - all performance calculated with 60% constant relative humidtiy.
5. Plant Performance is measured at the generator terminals and includes allowances for the effects of exitation power, shaft driven auxiliaries, and 3.04 in H2O (6.33 mbar) inlet and 5.5 in H2O (13.70 mbar) exhaust pressure drops and a DLN Combustor.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	% Effect on Heat Rate	Effect on Exhaust Temp.
4 in Water (10.0 mbar) inlet	-1.54	0.56	3.0F (1.7C)
4 in Water (10.0 mbar) exhaust	-0.56	0.56	3.0F (1.7C)



J. Van Deusen
5/19/98

543HA875
Rev - 0

GENERAL ELECTRIC MODEL PG7241(FA) GAS TURBINE

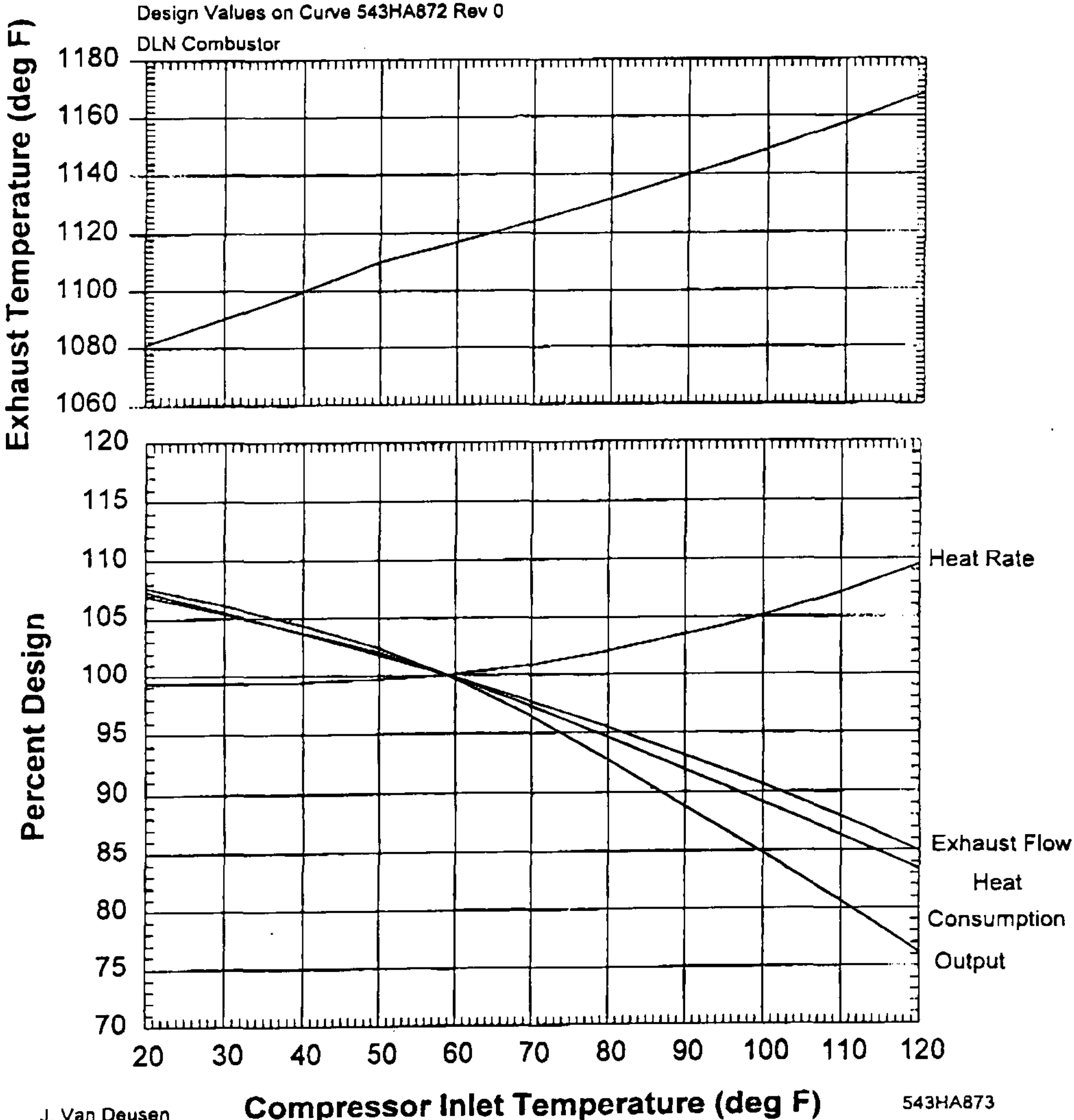
Jacksonville Electric Authority

Effect of Compressor Inlet Temperature on Output, Heat Rate, Heat Consumption, Exhaust Flow And Exhaust Temperature at Baseload

Fuel: Customer Specified Gas

Design Values on Curve 543HA872 Rev 0

DLN Combustor

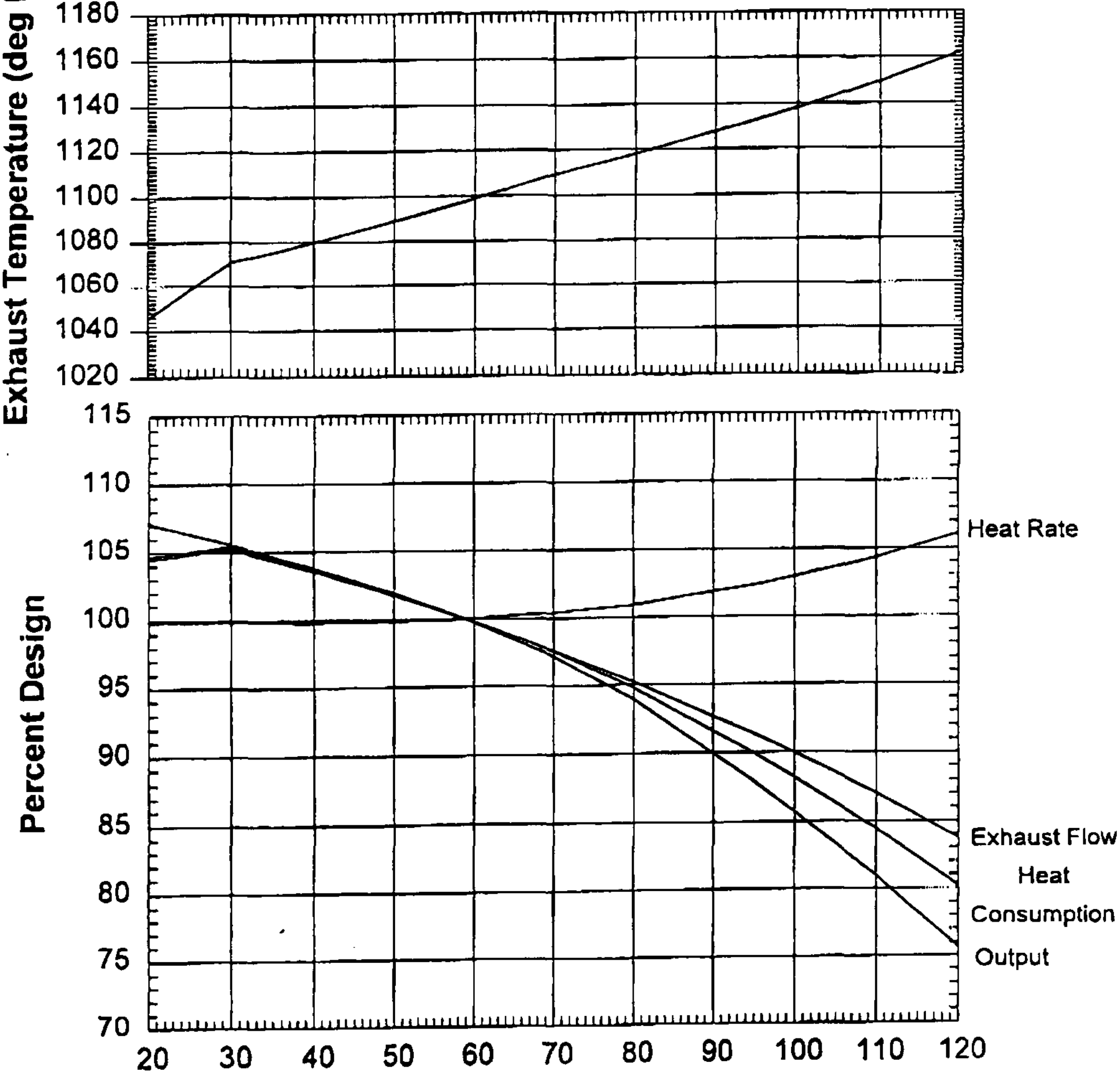


J. Van Deusen
5/18/98

543HA873
Rev - 0

GENERAL ELECTRIC MODEL PG7241(FA) GAS TURBINE
Jacksonville Electric Authority
Effect of Compressor Inlet Temperature on
Output, Heat Rate, Heat Consumption, Exhaust Flow
And Exhaust Temperature at Baseload

Fuel: Distillate
Design Values on Curve 543HA875 Rev 0
DLN Combustor



J. Van Deusen
5/19/98

543HA876
Rev - 0

Attachment 6 - Fuel Analysis or Specification

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

Attachment 7 - Control Equipment

The control equipment specified for this project consists of dry low NO_X burners to control NO_X emissions during natural gas firing and water injection to control NO_X emissions during fuel oil firing.

Attachment 8 - Description of Stack Sampling facilities

The stack sampling facilities will conform to FAC Chapter 62-297, attached.

TABLE OF CONTENTS
Chapter 62-297
Stationary Sources - Emissions Monitoring

Chapter 62-297
Stationary Sources - Emissions Monitoring

62-297.100 Purpose and Scope.
The Department of Environmental Protection adopts this chapter to establish test procedures that shall be used to determine the compliance of air pollutant emissions units with emission limiting standards specified in or established pursuant to any of the stationary source rules of the Department. Words and phrases used in this chapter, unless clearly indicated otherwise, are defined at Rule 62-210.200, F.A.C.
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(a); Formerly 17-297.100; Amended 11-23-94, 3-13-96.

62-297.200 Definitions. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.100; Amended 6-29-93; Formerly 17-297.200; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.310 General Compliance Test Requirements.
The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air.

(1) Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard.

(2) Operating Rate During Testing. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity as defined below. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

(a) Combustion Turbines. (Reserved)

(b) All Other Sources. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

(3) Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

(4) Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded Max. deviation between readings	Micrometer	+/-0.001" men of at least three readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

(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. inimum 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.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62- 210.300(4)(a)1. through 7., F.A.C.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

(8) Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.

2. The facility at which the emissions unit is located.

3. The owner or operator of the emissions unit.

4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.

11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.

14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.

16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(b); Formerly 17-297.310; Amended 11-23-94, 3-13-96, 10-28-97.

62-297.330 Applicable Test Procedures. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92, Formerly 17-297.330; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.340 Frequency of Compliance Tests. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(2); Formerly 17-297.340; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.345 Stack Sampling Facilities Provided by the Owner of an Emissions Unit. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(4), Formerly 17-297.345, Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.350 Determination of Process Variables. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(5), Formerly 17-297.350, Amended 11-23-94. Repealed 3-13-96.

62-297.400 EPA Methods Adopted by Reference. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(c), Formerly 17-297.400, Amended 11-23-94, Repealed 1-1-96.

62-297.401 Compliance Test Methods.

This rule adopts the test methods to be used where a compliance test is required by Department air pollution rule or air permit. The EPA test methods and quality assurance procedures listed in this rule and contained in 40 CFR Part 51, Appendix M, 40 CFR Part 60, Appendix A and F, 40 CFR Part 61, Appendix B and C and 40 CFR Part 63, Appendix A, are adopted and incorporated by reference in Rule 62-204.800, F.A.C. The EPA test methods that are adopted by reference in Rule 62-204.800, F.A.C., are adopted in their entirety except for those provisions referring to approval of alternative procedures by the Administrator. For purposes of this rule, such alternative procedures may only be approved by the Secretary or his or her designee in accordance with Rule 62-297.620, F.A.C.

(1)(a) EPA Method 1 -- Sample and Velocity Traverses for Stationary sources -- 40 CFR 60 Appendix A.

(b) EPA Method 1A -- Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts -- 40 CFR 60 Appendix A.

(2) EPA Method 2 -- Determination of Stack Gas Velocity and Volumetric Flow Rate -- 40 CFR 60 Appendix A.

(a) EPA Method 2A -- Direct Measurement of Gas Volume Through Pipes and Small Ducts -- 40 CFR 60 Appendix A.

(b) EPA Method 2B -- Determination of Exhaust Gas Volume Flow Rate from Gasoline Vapor Incinerators -- 40 CFR 60 Appendix A.

(c) EPA Method 2C -- Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks and Ducts (Standard Pitot Tube) -- 40 CFR 60 Appendix A

(d) EPA Method 2D -- Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts -- 40 CFR 60 Appendix A.

(3) EPA Method 3 -- Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight -- 40 CFR 60 Appendix A.

(a) EPA Method 3A -- Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A

(b) (Reserved).

(4) EPA Method 4 -- Determination of Moisture Content in Stack Gases -- 40 CFR 60 Appendix A.

(5) EPA Method 5 -- Determination of Particulate Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 5A -- Determination of Particulate Emissions from the Asphalt Processing and Asphalt Roofing Industry -- 40 CFR 60 Appendix A.

(b) EPA Method 5B -- Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(c) Reserved.

(d) EPA Method 5D -- Determination of Particulate Matter Emissions from Positive Pressure Fabric Filters -- 40 CFR 60 Appendix A.

(e) EPA Method 5E -- Determination of Particulate Emissions from the Wool Fiberglass Insulation Manufacturing Industry -- 40 CFR 60 Appendix A.

(f) EPA Method 5F -- Determination of Nonsulfate Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(g) EPA Method 5G -- Determination of Particulate Emissions from Wood Heaters from a Dilution Tunnel Sampling Location -- 40 CFR 60 Appendix A.

(h) EPA Method 5H -- Determination of Particulate Emissions from Wood Heaters from a Stack Location -- 40 CFR 60 Appendix A.

(6) EPA Method 6 -- Determination of Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 6A -- Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(b) EPA Method 6B -- Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(c) EPA Method 6C -- Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(7) EPA Method 7 -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 7A -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(b) EPA Method 7B -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Ultraviolet Spectrophotometry) -- 40 CFR 60 Appendix A.

(c) EPA Method 7C -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Colorimetric Method -- 40 CFR 60 Appendix A.

(d) EPA Method 7D -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(e) EPA Method 7E -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(8) EPA Method 8 -- Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(9)(a) EPA Method 9 -- Visual Determination of the Opacity of Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(b) Alternate Method 1 -- Determination of the Opacity of Emissions from Stationary Sources Remotely by Lidar -- 40 CFR 60 Appendix A.

(c) DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six- minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

(10) EPA Method 10 -- Determination of Carbon Monoxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 10A -- Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries -- 40 CFR 60 Appendix .

(b) EPA Method 10B -- Determination of Carbon Monoxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(11) EPA Method 11 -- Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries -- 40 CFR 60 Appendix A.

(12) EPA Method 12 -- Determination of Inorganic Lead Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(13) EPA Methods 13A and 13B.

(a) EPA Method 13A -- Determination of Total Fluoride Emissions from Stationary Sources -- SPADNS --- Zirconium Lake Method -- 40 CFR 60 Appendix A.

(b) EPA Method 13B -- Determination of Total Fluoride Emissions from Stationary Sources -- Specific Ion Electrode Method -- 40 CFR 60 Appendix A.

(14) EPA Method 14 -- Determination of Fluoride Emissions from Potroom Roof Monitors of Primary Aluminum Plants -- 40 CFR 60 Appendix A.

(15) EPA Method 15 -- Determination of Hydrogen Sulfide, Carbonyl Sulfide and Carbon Disulfide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 15A -- Determination of Total Reduced Sulfur Emissions from Sulfur Recovery Plants in Petroleum Refineries -- 40 CFR 60 Appendix A.

(16) EPA Method 16 -- Semicontinuous Determination of Sulfur Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 16A -- Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique) -- 40 CFR 60 Appendix A.

(b) EPA Method 16B -- Determination of Total Reduced Sulfur Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(17) EPA Method 17 -- Determination of Particulate Emissions from Stationary Sources (In-Stack Filtration Method) -- 40 CFR 60 Appendix A.

(18) EPA Method 18 -- Measurement of Gaseous Organic Compound Emissions by Gas Chromatography -- 40 CFR 60 Appendix A.

(19) EPA Method 19 -- Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates -- 40 CFR 60 Appendix A.

(20) EPA Method 20 -- Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines -- 40 CFR 60 Appendix A.

(21) EPA Method 21 -- Determination of Volatile Organic Compound Leaks -- 40 CFR 60 Appendix A.

(22) EPA Method 22 -- Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares -- 40 CFR 60 Appendix A.

(23) EPA Method 23 -- Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources -- 40 CFR 60 Appendix A.

(24) EPA Method 24 -- Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings -- 40 CFR 60 Appendix A.

(a) EPA Method 24A -- Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings -- 40 CFR 60 Appendix A.

(b) No change.

(25) EPA Method 25 -- Determination of Total Gaseous Nonmethane Organic Emissions as Carbon -- 40 CFR 60 Appendix A.

(a) EPA Method 25A -- Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer -- 40 CFR 60 Appendix A.

(b) EPA Method 25B -- Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer -- 40 CFR 60 Appendix A.

(26) EPA Method 26 -- Determination of Hydrogen Chloride Emissions From Stationary Sources -- 40 CFR 60, Appendix A.

(a) EPA Method 26A -- Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources - Isokinetic Method -- 40 CFR 60, Appendix A

(27) EPA Method 27 -- Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test -- 40 CFR 60 Appendix A.

(28) EPA Method 28 -- Certification and Auditing of Wood Heaters -- 40 CFR 60 Appendix A.

(a) EPA Method 28A -- Measurement of Air to Fuel Ratio and Minimum Achievable Burn Rates for Wood-Fired Appliances -- 40 CFR 60 Appendix A.

(29) EPA Method 29 -- Determination of Metals Emission from Stationary Sources -- 40 CFR 60 Appendix A.

(30) Reserved.

(31) 40 CFR 60 Appendix F -- Quality Assurance Procedures -- .

(32) EPA Method 101 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Air Streams -- 40 CFR 61 Appendix B.

(a) EPA Method 101A -- Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators -- 40 CFR 61 Appendix B.

(33) EPA Method 102 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Hydrogen Streams -- 40 CFR 61 Appendix B.

(34) EPA Method 103 -- Beryllium Screening Method -- 40 CFR 61 Appendix B.

(35) EPA Method 104 -- Determination of Beryllium Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(36) EPA Method 105 -- Determination of Mercury in Wastewater Treatment Plant Sewage Sludges -- 40 CFR 61 Appendix B.

(37) EPA Method 106 -- Determination of Vinyl Chloride Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(38) EPA Method 107 -- Determination of Vinyl Chloride Content of Inprocess Wastewater Samples, and Vinyl Chloride Content of Polyvinyl Chloride Resin, Slurry, Wet Cake, and Latex Samples -- 40 CFR 61 Appendix B.

(a) EPA Method 107A -- Determination of Vinyl Chloride Content of Solvents, Resin-Solvent Solution, Polyvinyl Chloride Resin, Resin Slurry, Wet Resin, and Latex Samples -- 40 CFR 61 Appendix B.

(39) EPA Method 108 -- Determination of Particulate and Gaseous Arsenic Emissions -- 40 CFR 61 Appendix B.

(a) EPA Method 108A -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(b) EPA Method 108B -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(c) EPA Method 108C -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(40) 40 CFR 61 Appendix C -- Quality Assurance Procedures.

(41) EPA Method 201 -- Determination of PM_{10} Emissions (Exhaust Gas Recycle Procedure) -- 40 CFR 51 Appendix M.

(a) EPA Method 201A -- Determination of PM_{10} Emissions (Constant Sampling Rate Procedure) -- 40 CFR 51 Appendix M.

(42) EPA Method 202 -- Determination of Condensible Particulate Emissions from Stationary Sources -- 40 CFR 51 Appendix M.

(43) EPA Method 301 -- Field Data Validation Protocol -- 40 CFR Part 63, Appendix A.

(44) EPA Method 303 -- Coke Oven Door Emissions -- 40 CFR Part 63, Appendix A.
Specific Authority 403.061 FS.
Law Implemented 403.021, 403.031, 403.061, 403.087 FS.
History Formerly 17-2.700(6)(b), Amended 10-14-92, 6-29-93; Formerly 17-297.401; Amended 11-23-94, 1-1-96, 3-13-96, 10-7-96.

62-297.411 DEP Method 1. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)1, Formerly 17-297.411, Amended 11-23-94, Repealed 1-1-96.

62-297.412 DEP Method 2 (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)2, Formerly 17-297.412, Repealed 1-1-96.

62-297.413 DEP Method 3. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)3, Formerly 17-297.413, Repealed 1-1-96.

62-297.414 DEP Method 4. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)4, Formerly 17-297.414, Repealed 1-1-96.

62-297.415 DEP Method 5. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.a, Formerly 17-297.415; Amended 11-23-94, Repealed 1-1-96.

62-297.416 DEP Method 5A. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.b, Formerly 17-297.416, Repealed 1-1-96.

62-297.417 DEP Method 6. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)6, Formerly 17-297.417, Amended 11-23-94, Repealed 1-1-96.

62-297.418 DEP Method 7. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)7, Formerly 17-297.418, Repealed 1-1-96.

62-297.419 DEP Method 8. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)8, Formerly 17-297.419, Repealed 1-1-96.

62-297.420 DEP Method 9. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)9, Formerly 17-297.420, Amended 11-23-94, Repealed 3-13-96.

62-297.421 DEP Method 10. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)10, Formerly 17-297.421, Repealed 1-1-96.

62-297.422 DEP Method 11. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 62-2.700(6)(a)11, Formerly 17-297.422, Repealed 1-1-96.

62-297.423 EPA Method 12. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)12, Formerly 17-297.423, Amended 11-23-94, 1-1-96.

62-297.424 DEP Method 13. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)13, Formerly 17-297.424, Repealed 1-1-96.

62-297.440 Supplementary Test Procedures.
The following test procedures are adopted by reference. Copies of these documents are available from the emissions units set forth below. Copies may also be inspected at the Department's Tallahassee Office.

(1) ASTM Methods. Standard Methods published by the American Society for Testing and Materials are available from the Society at 1916 Race Street, Philadelphia, Pennsylvania 19103.

(a) ASTM D 322-67, 1972. Standard Method of Test for Dilution of Gasoline Engine Crankcase Oils.

(b) ASTM D 396-76. Standard Specification for Fuel Oils, superceding ASTM D 396-69.

(c) ASTM D 2880-76. Standard Specification for Gas Turbine Fuel Oils, superceding ASTM D 2880-71.

(d) ASTM D 975-77. Standard Specification for Diesel Fuel Oils, superceding ASTM D 975-68.

(e) ASTM D 323-72. Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method).

(f) ASTM D 97-66. Standard Test Method for Pour Point of Petroleum Oils.

(g) ASTM D 4057-88. Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(h) ASTM D 129-91. Standard Test Method for Sulfur in Petroleum Products (General Bomb Method).

(i) ASTM D 2622-94. Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry.

(j) ASTM D 4294-90. Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy.

(2) EPA Reports -- EPA occasionally publishes test methods and emission control guidelines in a report format. These documents are available (unless otherwise stated) from the National Technical Information Services, 5286 Port Royal Road, Springfield, Virginia 22216, and may be inspected at the Department's Tallahassee Office.

(a) Petroleum Liquid Storage.

1. Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, EPA 450/2-78-047, p. 5-3.

2. Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed- Roof Tanks, EPA 450/2-77-036, p. 6-2.

(b) Gasoline Bulk Terminals.

1. Vapor Control System Test.

a. VOC emissions from the vapor control system shall be determined by the method given in Appendix A of EPA 450/2-77-026, except that an adequate sampling time shall be at least six (6) hours of operation. For continuous vapor processing systems at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test. For intermittent vapor processing systems, at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test and at least two full cycles of operation of the vapor processing system shall occur. This test shall be performed prior to the date of compliance and annually thereafter. Test results records shall be maintained at the terminal until the subsequent annual test shall be made available to the Department upon request.

b. Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals, EPA 450/2-77-026, Appendix A. Emission Test Procedure for Tank Truck Gasoline Loading Terminals.

2. Vapor Leak Detection.

a. During loading or unloading operations at bulk terminals, there shall be no reading greater than or equal to 100 percent of the lower explosive level (LEL), measured as propane at 1 in. (2.5 centimeters) around the perimeter of a potential leak source as detected by a combustible gas detector using the procedure described in Appendix B of EPA 450/2-78-051.

b. Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems, EPA 450/2-78-051, Appendix B, Gasoline Vapor Leak Detection Procedures by Combustible Gas Detector.

(c) Gasoline Service Stations.

1. Design Criteria for Stage I Vapor Control: Gasoline Service Stations, USEPA, OAQPS, ESED, November, 1975.

2. [Reserved]

(d) Non-destructive Control Devices.

1. Measurement of Volatile Organic Compounds, EPA 450/2-78-041, Attachment 3, Alternate Test for Direct Measurement of Total Gaseous Organic Compounds Using a Flame Ionization Analyzer.

2. [Reserved]

(e) Perchloroethylene Dry Cleaning Systems.

1. Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems, EPA 450/2-78-050, p. 6-3, Compliance Procedures, Liquid Leakage.

2. RACT Compliance Guidance for Carbon Absorbers on Perchloroethylene Dry Cleaners. Task No. 119, Contract No. 68-01-4147. EPA, DSSE, May, 1980, pp. 8-21, Appendices A and B.

(f) Cross Recovery Determination. When determining if a kraft recovery furnace is a straight kraft or cross recovery furnace the procedure in 40 CFR 60.285(d)(3) of Subpart BB shall be used.

(3) American Conference of Governmental Industrial Hygienists, Recommended Practices -- Industrial Ventilation: A Manual of Recommended Practice. Equipment Specifications published in the 16th Edition of the Industrial Ventilation Manual (or any subsequent versions approved by the Department) are available from the American Conference of Governmental Industrial Hygienists, Committee on Industrial Ventilation, P. O. Box 16153, Lansing, Michigan 48901, and may be inspected at the Department's Tallahassee Office.

(4) American Petroleum Institute (API) Recommended Practices -- These are available from the API, 2101 L Street, Northwest, Washington, D. C. 20037

(a) API Standard 650, Welded Steel Tanks for Oil Storage, Sixth Edition, Revision 1, May 15, 1978.

(b) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February, 1980.

(c) API 1004, Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles, Fourth Edition, September 1, 1977.

(5) Technical Association of the Pulp and Paper Industry (TAPPI), Test Methods -- These are available from TAPPI, P. O. Box 105113, Atlanta, Georgia 30348.

(a) TAPPI Method T.624, Analysis of Soda and Sulfate White and Green Liquors.

(b) (Reserved).

(6) Sulphur Development Institute of Canada (SUDIC) Sampling and Testing Sulphur Forms -- These are available from SUDIC, Box 950, Bow Valley Square 1, 830, 202-6 Avenue S. W., Calgary, Alberta T2P 2W6.

(a) S1-77. Collection of a Gross Sample of Sulphur.

(b) S2-77. Sieve Analysis of Sulphur Forms, except paragraph 4.3 concerning wet sieving is not adopted.

(c) S3-77. Determination of Material Finer than No. 50 (300um) Sieve in Sulphur Forms by Washing.

(d) S5-77. Determination of Friability of Sulfur Forms.

(7) EPA VOC Capture Efficiency Test Procedures. Adopted by reference is an EPA memo dated April 16, 1990 entitled, "Guidelines for Developing a State Protocol for the Measurement of Capture Efficiency." A copy can be obtained by writing to: Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(a) Procedure F.1 -- Fugitive VOC Emissions from Temporary Enclosures.

(b) Procedure F.2 -- Fugitive VOC Emissions from Building Enclosures.

(c) Procedure G.1 -- Captured VOC Emissions.

(d) Procedure G.2 -- Captured VOC Emissions (dilution technique).

(e) Procedure L -- VOC in Liquid Input Stream.

(f) Procedure T -- Criteria for and Verification of Permanent or Temporary Total Enclosure.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(c); Amended 6-29-93, Formerly 17-297.440, Amended 11-23-94, 1-1-96.

62-297.450 EPA VOC Capture Efficiency Test Procedures.

(1) Applicability. The requirements set forth in Rules 62-297.450(2) and (3), F.A.C., shall apply to all regulated VOC emitting emissions units employing a control system pursuant to Rules 62-296.501 through 62-296.516, F.A.C., and Rule 62-296.800, F.A.C., except as provided in Rules 62-297.450(1)(a) and (b), F.A.C.

(a) If an owner or operator installs a Permanent Total Enclosure that meets the specifications of Procedure T, and which directs all VOC to a control device, the capture efficiency is assumed to be 100 percent, and the facility owner or operator is exempted from the requirements described in Rule 62-297.450(2) , F.A.C. This does not exempt the owner or operator from conducting any required control device efficiency test.

(b) If the owner or operator of an affected activity, process, or emissions unit uses a nondestructive control device designed to collect and recover VOC (e.g. carbon adsorber), an explicit measurement of capture efficiency is not necessary if the owner or operator is able to equate solvent usage with solvent recovery on a 24-hour (daily) basis, rather than a 30-day weighted average, and can determine this within 72 hours following each 24-hour period, and one of the following two criteria is also met:

1. The solvent recovery system (i.e., capture and control system) is dedicated to a single activity, process line, or emissions unit (e.g., one process line venting to a carbon adsorber system), or

2. The solvent recovery system controls multiple activities, process lines, or emissions units and the owner or operator is able to demonstrate that the overall control (i.e., the total recovered solvent VOC divided by the sum of liquid VOC input to all activities, process lines, or emissions units venting of the control system) meets or exceeds the most stringent emission standard applicable for any activity, process line, or emissions unit venting to the control system.

(c) If the conditions given above in Rule 62-297.450(1)(b), F.A.C., are met, the overall emission reduction efficiency of the system can be determined by dividing the recovered liquid VOC by the input liquid VOC. The general procedure for this determination is given in 40 CFR 60.433, which is adopted by reference.

(2) Specific Requirements. The capture efficiency of a capture system shall be determined using one of the following EPA procedures, or an alternate capture efficiency test procedure if approved by the Department under the provisions of Rule 62-297.620, F.A.C.

(a) Gas/gas method using a Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = Gw/(Gw + Fw)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
Gw = mass of VOC captured and delivered to control device using a Temporary Total Enclosure

Fw = mass of fugitive VOC that escapes from a Temporary Total Enclosure Procedure G.1 or Procedure G.2 is used to obtain Gw. Procedure F.1 is used to obtain Fw.

(b) Liquid/gas method using Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F = mass of fugitive VOC that escapes from a Temporary Total Enclosure Procedure L is used to obtain L. Procedure F.1 is used to obtain F.

(c) Gas/gas method using the building or room in which the affected activity, process, or emissions unit is located as the enclosure and in which G and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room must be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = G/(G + F \text{ sub } B)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
G = mass of VOC captured and delivered to a control device
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure G.1 or Procedure G.2 is used to obtain G. Procedure F.2 is used to obtain F_B.

(d) Liquid/gas method using the building or room in which the affected activity, process, or emissions unit located as the enclosure and in which L and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room shall be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F_B)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure L is used to obtain L. Procedure F.2 is used to obtain F sub B.

(3) Sampling Requirements. A capture efficiency test shall consist of at least three sampling runs. Each run shall cover at least one complete production cycle, but shall be at least 3 hours long. The sampling time for each run need not exceed 8 hours, even if the production cycle has not been completed.

(4) Recordkeeping and Reporting.

(a) The owner or operator of an affected activity, process, or emissions unit shall submit to the Department a list of the procedures that will be used for the capture efficiency tests at the owner or operator's facility. A copy of the list shall be kept on file at the affected facility.

(b) Required test reports shall be submitted to the Department within forty-five (45) days of the test date. A copy of the results shall be kept on file at the facility.

(c) If any physical or operational change is made to a control system, the owner or operator of the affected facility shall notify the Department of the change within ten (10) working days after making such change. The Department shall require the owner or operator of the affected activity, process, or emissions unit to conduct a new capture efficiency test if the Department has reason to believe (based on engineering calculations or empirical evidence) that a physical or operational change made to the capture system has decreased the overall emissions reduction efficiency of the system.

(d) Notwithstanding the provisions of Rule 62-297.340(1), F.A.C., the owner or operator of an affected activity, process, or emissions unit shall notify the Department thirty (30) days prior to performing any capture efficiency and/or control efficiency tests.

(e) The owner or operator of an affected activity, process, or emissions unit using a Permanent Total Enclosure shall demonstrate that this enclosure meets the requirement given in Procedure T for a Permanent Total Enclosure during any required control device efficiency test.

(f) The owner or operator of an affected activity, process, or emissions unit using a Temporary Total Enclosure shall demonstrate that this enclosure meets the requirements given in Procedure T for a Temporary Total Enclosure during any required control device efficiency test.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(7); Amended 6-29-93, Formerly 17-297.450, Amended 11-23-94, 1-1-96.

62-297.500 Continuous Emission Monitoring Requirements. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92; 6-29-93; Formerly 17-297.500; Repealed 11-23-94.

62-297.520 EPA Continuous Monitor Performance Specifications.

This rule adopts the continuous monitor performance specifications to be used where required by Department air pollution rule or air permit. The EPA performance specifications listed in this rule and contained in 40 CFR 60, Appendix B, are adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 3--Specifications and Test Procedures for O_2 and CO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(4) Performance Specification 4--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(5) Performance Specification 4A--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(6) Performance Specification 5--Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources.

(7) Performance Specification 6--Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources.

(8) Performance Specification 7--Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: New 6-29-93, Formerly 17-297.520, Amended 11-23-94, 3-13-96.

62-297.570 Test Reports. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(8), Formerly 17-297.570, Amended 11-23-94, Repealed 3-13-96.

62-297.620 Exceptions and Approval of Alternate Procedures and Requirements.

(1) The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

(2) The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

(3) The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.

(4) In the case of an emissions unit which has the potential to emit less than 100 tons per year of particulate matter and is equipped with a baghouse, the Secretary or the appropriate Director of District Management may waive any particulate matter compliance test requirements for such emissions unit specified in any otherwise applicable rule, and specify an alternative standard of 5% opacity. The waiver of compliance test requirements for a particulate emissions unit equipped with a baghouse, and the substitution of the visible emissions standard, shall be specified in the permit issued to the emissions unit.

If the Department has reason to believe that the particulate weight emission standard applicable to such an emissions unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(3); Amended 6-29-93; Formerly 17-297.620; Amended 11-23-94.