J.R. KELLY GENERATING STATION

TITLE V OPERATION PERMIT
RENEWAL APPLICATION

Prepared for:

GRU[SM]

More than Energy™

Gainesville, Florida

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street

Gainesville, Florida 32606

ECT No. 030413-0100

June 2003

INTRODUCTION

The City of Gainesville, Gainesville Regional Utilities (GRU) J.R. Kelly Generating Station located in Gainesville, Alachua County, Florida, is a nominal 192-megawatt (MW) electric generation facility. The J.R. Kelly Generating Station consists of one steam boiler/steam turbine generator (STG) unit (Unit No. 7), three simple-cycle combustion turbines (Units CT-1, CT-2, and CT-3), one combined/simple-cycle combustion turbine unit (Unit CC-1), a recirculating cooling water system, fuel oil storage tanks, water treatment facilities, and ancillary support equipment. CC-1 is comprised of one combustion turbine generator (CTG) and one unfired heat recovery steam generator (HRSG). CC-1 HRSG is equipped with a bypass stack to allow for the option of simple-cycle operation. Steam produced by CC-1 HRSG is used by existing Unit No. 8 STG to generate additional electricity. Existing steam boiler Unit Nos. 6 and 8 have permanently ceased operation.

Unit No. 7 is fired primarily with natural gas; residual fuel oils (Nos. 4, 5, or 6) are used as a back-up fuel source. When firing residual oils, Unit No. 7 may be supplemented with on-specification used oil. Combustion turbines Nos. 1, 2, and 3 and CC-1 CTG are fired with natural gas or/and No. 2 fuel oil.

Additional facilities owned by GRU are located adjacent to the J.R. Kelly Generating Station. These facilities include vehicle fleet maintenance (vehicle servicing, cleaning, and refueling), GRU administration building, area used by the water/wastewater department for storage of equipment and bulk materials, administrative offices for meter readers, water department distribution operations (administration offices, construction equipment yard, and vehicle parking), carpenter shop, two warehouses for equipment and materials storage, transformer shop (electrical equipment storage, testing, maintenance, dielectric fluid storage tanks, and a paint spray booth), and a building for storage of equipment that may contain polychlorinated biphenyls (PCBs).

Pursuant to Rule 62-213.420(1)(a)3 and Section 62-4.090, Florida Administrative Code (F.A.C.), an application for renewal of a Title V operation permit must be submitted

180 days prior to expiration. Since FINAL Title V Permit No. 0010005-003-AV expires on December 31, 2003, the permit renewal application for the J.R. Kelly Generating Station must be submitted no later than July 5, 2003. This application package, consisting of the Florida Department of Environmental Protection's (FDEP's) *Application for Air Permit—Title V Source* and all required supplemental facility and emission unit information constitutes GRU's Title V permit renewal application for the J.R. Kelly Generating Station and is submitted to satisfy the requirements of Section 62-213.400, F.A.C. Regulatory applicability analyses and proposed Title V permit conditions are provided in Appendices A and B, respectively.

Department of
Environmental Protection

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BUREAU OF AIR REGULATION

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **City of Gainesville Gainesville Regional Utilities (GRU)**	
2. Site Name: **J.R. Kelly Generating Station**	
3. Facility Identification Number: **0010005** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **605 SE 3rd Street** City: **Gainesville** County: **Alachua** Zip Code: **32601-7060**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [✔] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Yolanta Jonynas** **Environmental Resource Coordinator**
2. Application Contact Mailing Address: Organization/Firm: **City of Gainesville, Gainesville Regional Utilities (GRU)** Street Address: **P.O. Box 147117 (A136)** City: **Gainesville** State: **FL** Zip Code: **32614-7117**
3. Application Contact Telephone Numbers: Telephone: **(352) 393-1284** Fax: **(352) 334-3151**

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number: ____________________

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

Current construction permit number: ____________________

Operation permit number to be revised: ____________________

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

Operation permit number to be revised/corrected: ____________________

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

Operation permit number to be revised: **0010005-003-AV**

Reason for revision: **Operation permit renewal**

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Randy L. Casserleigh, Interim Assistant General Manager Energy Supply**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **City of Gainesville, Gainesville Regional Utilities (GRU)** Street Address: **P.O. Box 147117 (A134)** City: **Gainesville** State: **FL** Zip Code: **32614-7117**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(352) 393-1789** Fax: **(352) 334-2786**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✔], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Signature: [signature] Date: 6-23-03

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address: Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606-5004**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444** Fax: **(352) 332-6722**

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.

Thomas W. Dunn   6/23/03

Signature   Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
007	Fossil Fuel Fired Steam Generator Unit No. 7	N/A	N/A
009	Simple Cycle Combustion Turbines Units CT-1, CT-2, and CT-3	N/A	N/A
010	Combined Cycle Unit No. 1 (CC-1)	N/A	N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $ ________ [✔] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations:

The City of Gainesville, Gainesville Regional Utilities (GRU) J.R. Kelly Generating Station consists of one fossil fuel fired steam generator (Unit No. 7), one combined/simple cycle combustion turbine unit (CC-1), and three simple cycle combustion turbines (CT-1, CT-2, and CT-3). Unit No. 7 is fired with natural gas and/or residual fuel oils (Nos. 4, 5, or 6). Residual fuel oils fired in Unit 7 may be supplemented with on-specification used oil. CC-1 is comprised on one dual fuel (natural gas or distillate fuel oil) combustion turbine generator (CTG) and one, unfired heat recovery steam generator (HRSG). CC-1 HRSG is equipped with a bypass stack to allow for simple cycle operation. Steam produced by CC-1 HRSG is utilized by existing Unit 8 steam turbine generator (STG) for the production of additional electricity. CT-1, CT-2, and CT-3 are fired with either natural gas or distillate fuel oil. Existing fossil fuel fired steam generators Unit No. 6 and Unit No. 8 have permanently ceased operations.

Operation of the J.R. Kelly Generating Station is presently authorized by Department FINAL Permit Revision No. 0010005-003-AV. This permit was issued with a revision effective date of December 5, 2000 and an expiration date of December 31, 2003. Pursuant to Rules 62-213.420(1)(a)3. and 62-4.090, Florida Administrative Code (F.A.C.), an application for permit renewal must be submitted at least 180 days prior to permit expiration, or by July 5, 2003 for FINAL Permit Revision No. 001005-003-AV. This application constitutes GRU's Title V permit renewal application for the J.R. Kelly Generating Station.

2. Projected or Actual Date of Commencement of Construction: **N/A**

3. Projected Date of Completion of Construction: **N/A**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **372.0**	North (km): **3,280.2**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: **4**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Yolanta Jonynas, Environmental Resource Coordinator**			
2. Facility Contact Mailing Address: Organization/Firm: **City of Gainesville, Gainesville Regional Utilities (GRU)**			
Street Address: **P.O. Box 147117 (A136)**			
City: **Gainesville**	State: **FL**	Zip Code: **32614-7117**	
3. Facility Contact Telephone Numbers: Telephone: **(352) 393-1284**	Fax: **(352) 334-3151**		

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [✔] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [✔] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

See Appendix A	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

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

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [✔] Attached, Document ID: **DOC. II.C.1** [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [✔] Attached, Document ID: **DOC. II.C.2** [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [✔] Attached, Document ID: **DOC. II.C.3** [ ] Not Applicable [ ] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [✔] Attached, Document ID: **DOC. II.C.4** [ ] Not Applicable [ ] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID:__________ [✔] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID: [✔] Not Applicable	
7. Supplemental Requirements Comment: **Not applicable**	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

[✔] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Fossil Fuel Fired Steam Generator Unit No. 7

4. Emissions Unit Identification Number: [ ] No ID
ID: **007** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**N/A**	**49**	[ ]

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **None**
2. Control Device or Method Code(s): **N/A**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating: **25** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**272** mmBtu/hr			
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Generator nameplate rating shown of 25 MW is at a 0.85 power factor.** **Maximum heat input rate shown is for natural gas combustion.** **Maximum heat input rate is 249 mmBtu/hr for residual fuel oil combustion.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Appendix A	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **JRK-7**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

N/A

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

5. Discharge Type Code: **V**	6. Stack Height: **200** feet	7. Exit Diameter: **10.5 ft**
8. Exit Temperature: **344** °F	9. Actual Volumetric Flow Rate: **114,707** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

Exit temperature (Field No. 8) and actual flow rate (Field No. 9) taken from September/October 2002 stack test report.

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Residual fuel oils burned in Unit No. 7**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.660**	5. Maximum Annual Rate: **14,541.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **150**
10. Segment Comment (limit to 200 characters): **Maximum hourly and annual fuel rates based on 249 mmBtu/hr heat input and a nominal residual fuel oil heat content of 150,000 Btu/gal.** **Residual fuel oils may be supplemented with on-specification used oil.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Pipeline quality natural gas burned in Unit No. 7**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.262**	5. Maximum Annual Rate: **2,291.1**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,040**
10. Segment Comment (limit to 200 characters): **Maximum hourly and annual fuel rates based on 272 mmBtu/hr heat input and a nominal natural gas heat content of 1,040 Btu/ft^3.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – CO	**N/A**	**N/A**	**NS**
2 – NOX	**N/A**	**N/A**	**NS**
3 – PM	**N/A**	**N/A**	**EL**
4 – PM10	**N/A**	**N/A**	**NS**
5 – SO2	**N/A**	**N/A**	**EL**
6 – VOC	**N/A**	**N/A**	**NS**

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **81.6** lb/hour **148.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.1 and 0.3 lb/mmBtu** Reference: **Conditions B.6 and B.7 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**

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

Hourly emission rate based on 0.3 lb/10^6 Btu during soot blowing.
Hourly PM = (0.3 lb/mmBtu) x (272.0 mmBtu/hr) = 81.6 lb/hr

Annual emission rate based on 0.3 lb/10^6 Btu during soot blowing (for 3 hrs/dy) and 0.1 lb/10^6 Btu (for 21 hrs/dy) during non-soot blowing.
Annual PM = (0.125 lb/mmBtu) x (272.0 mmBtu/hr) x (8,760 hr/yr) x (1 ton/2,000 lb)
Annual PM = 148.9 ton/yr

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

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **27.2** lb/hour **148.9** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Methods 5, 5B, 5F, or 17.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
Allowable emission rates applicable for natural gas-firing.

Annual allowable emission rate based on 0.3 lb/10^6 Btu during soot blowing (for 3 hrs/dy) and 0.1 lb/10^6 Btu (for 21 hrs/dy) during non-soot blowing.

Rule 62-296.405(1)(b), F.A.C.

Pollutant Detail Information Page 2 of 5

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.3 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **81.6** lb/hour **148.9** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 5, 5B, 5F, or 17.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable for natural gas-firing during soot blowing and load change.** **Annual allowable emission rate based on 0.3 lb/10^6 Btu during soot blowing (for 3 hrs/dy) and 0.1 lb/10^6 Btu (for 21 hrs/dy) during non-soot blowing.** **Rule 62-210.700(3), F.A.C.**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **0.1 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **24.9** lb/hour **136.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 5, 5B, 5F, or 17.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emission rates applicable for residual fuel oil-firing.** **Annual allowable emission rate based on 0.3 lb/10^6 Btu during soot blowing (for 3 hrs/dy) and 0.1 lb/10^6 Btu (for 21 hrs/dy) during non-soot blowing.** **Rule 62-296.405(1)(b), F.A.C.**	

Pollutant Detail Information Page 3 of 5

Allowable Emissions Allowable Emissions __4__ of __4__

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **0.3 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **74.7** lb/hour **136.3** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Methods 5, 5B, 5F, or 17.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
Limit applicable for residual fuel oil-firing during soot blowing and load change.

Annual allowable emission rate based on 0.3 lb/10^6 Btu during soot blowing (for 3 hrs/dy) and 0.1 lb/10^6 Btu (for 21 hrs/dy) during non-soot blowing.

Rule 62-210.700(3), F.A.C.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **684.8** lb/hour **2,999.2** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **2.75 lb/10^6 Btu** Reference: **Condition B.8 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**

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

Hourly SO_2 = (2.75 lb/mmBtu) x (249.0 mmBtu/hr) = 684.8 lb/hr

Annual SO_2 = (2.75 lb/mmBtu) x (249.0 mmBtu/hr) x (8,760 hr/yr) x (1 ton/2,000 lb)
Annual SO_2 = 2,999.2 ton/yr

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.75 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **648.8** lb/hour **2,999.2** tons/year

5. Method of Compliance (limit to 60 characters):
Fuel oil sulfur analyses using ASTM D2622-92, ASTM D4294-90, ASTM D1552-90, ASTM D129-91, or

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

Allowable emission rates applicable for residual fuel oil-firing.

Rule 62-296.405(1)(c)1.j., F.A.C.

Pollutant Detail Information Page 5 of 5

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **2.5 weight percent sulfur fuel oil**	4. Equivalent Allowable Emissions: **648.8** lb/hour **2,999.2** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel oil sulfur analyses using ASTM D2622-92, ASTM D4294-90, ASTM D1552-90, ASTM D129-91, or latest editions of these ASTM methods.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emission rates applicable for residual fuel oil-firing.** **Rule 62-296.405(1)(e)3., F.A.C. and 10/30/97 applicant request.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 4

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [✔] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: **40** %
Maximum Period of Excess Opacity Allowed: **2** min/hour

4. Method of Compliance:
EPA Reference Method 9

5. Visible Emissions Comment (limit to 200 characters):

Rule 62-296.405(1)(e)1., F.A.C.

Annual testing is not required if fuel oil is not burned, other than during startup, for more than 400 hours per federal fiscal year.

Visible Emissions Limitation: Visible Emissions Limitation 2 of 4

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: [✔] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: **60** %
Maximum Period of Excess Opacity Allowed: **60** min/hour

4. Method of Compliance:
DEP Reference Method 9

5. Visible Emissions Comment (limit to 200 characters):

Maximum period of excess opacity allowed for 3 hours in any 24-hour period during soot blowing and load changes.

Rule 62-210.700(3), F.A.C.

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 4

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: **DEP Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): *** Best operational practices to minimize emissions and duration.** **Excess emissions resulting from startups and shutdowns.** **Rule 62-210.700(2), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation 4 of 4

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: **DEP Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): *** Best operational practices to minimize emissions and duration.** **Excess opacity allowed for startups, shutdowns, and malfunctions.** **Maximum period of excess emissions allowed is two hours in any 24-hour period unless authorized by the Department for a longer duration.** **Rule 62-210.700(1), F.A.C.**	

I. CONTINUOUS MONITOR INFORMATION – NOT APPLICABLE
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] 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):	

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] 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):	

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

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **DOC. II.C.3** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **DOC. III.J.2** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [✔] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [✔] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously submitted, Date: ________________ [✔] Not Applicable
6. Procedures for Startup and Shutdown [✔] Attached, Document ID: **DOC. III.J.6** [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [✔] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: ________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [✔] Attached, Document ID: **DOC. III.J.11**   [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [✔] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [✔] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [✔] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] 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:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [✔] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

[ ] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Simple Cycle Combustion Turbines CT-1, CT-2, and CT-3

4. Emissions Unit Identification Number: [ ] No ID
ID: **009** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**N/A**	**49**	[ ]

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **None**
2. Control Device or Method Code(s): **N/A**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating: **16.3** MW **(Per CT)**	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	mmBtu/hr	
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram?	2. Emission Point Type Code:	
3. Descriptions of Emission 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:	6. Stack Height: feet	7. Exit Diameter:
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone:	East (km):	North (km):
14. Emission Point Comment (limit to 200 characters):		

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Pipeline quality natural gas burned in CT-1, or CT-2, or CT-3 (per CT)

2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.192**	5. Maximum Annual Rate: **1,684.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,040**

10. Segment Comment (limit to 200 characters):

Maximum hourly and annual fuel rates based on base load conditions at 80°F, 14.7 psia, 200 mmBtu/hr heat input, and nominal fuel heating value of 1,040 Btu/ft^3.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Distillate fuel oil burned in CT-1, or CT2, or CT-3 (per CT).

2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.511**	5. Maximum Annual Rate: **13,235.9**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **137,000**

10. Segment Comment (limit to 200 characters):

Maximum hourly and annual fuel rates based on base load conditions at 80°F, 14.7 psia, 207 mmBtu/hr heat input, and nominal fuel heating value of 137,000 Btu/gal.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – CO	**N/A**	**N/A**	**NS**
2 – NOX	**N/A**	**N/A**	**NS**
3 – PM	**N/A**	**N/A**	**NS**
4 – PM10	**N/A**	**N/A**	**NS**
5 – SO2	**N/A**	**N/A**	**NS**
6 – VOC	**N/A**	**N/A**	**NS**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: Reference:		7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

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):	

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):	

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

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] 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):	

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] 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):	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

[✔] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one General Electric (GE) 7121 7EA combustion turbine generator (CTG). The CTG may operate in simple-cycle or combined-cycle modes of operation. The CTG will be fired with pipeline quality natural gas or low-sulfur distillate fuel oil.

4. Emissions Unit Identification Number: [ ] No ID
ID: **010 (CC-1)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**N/A**	**49**	[✔]

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

Emissions Unit Control Equipment

Not applicable. Unit is equipped with pollution prevention equipment (i.e., dry low-NO_x combustors [during natural gas-firing] and water injection [during distillate fuel oil-firing]) to reduce NO_x formation.
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **PG7121 (7EA)**
2. Generator Nameplate Rating: **96.1** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,120.5 (HHV)** mmBtu/hr			
2. Maximum Incineration Rate:	lb/hr		tons/day	
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):				

Maximum heat input is higher heating value (HHV) at 100 percent load, 20°F, fuel oil-firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.

Maximum Unit CC-1 annual operating hours are 8,760 and 1,000 hours per year (hr/yr) for natural gas and distillate fuel oil firing, respectively.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Appendix A	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CC-1, Bypass CC-1**	1. Emission Point Type Code: **3**

2. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

CC-1: Combined-cycle mode, HRSG outlet stack.
Bypass CC-1: Simple-cycle mode, HRSG bypass stack.

3. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

4. Discharge Type Code: **V**	6. Stack Height: **CC-1 102** feet **Bypass CC-1 88** feet	7. Exit Diameter: **CC-1 15.5** feet **Bypass CC-1 15.5** feet
8. Exit Temperature: **242** °F	9. Actual Volumetric Flow Rate: **704,482** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

Stack temperature and flow rate are for combined-cycle, 100 percent load, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with operating mode, load, fuel type, and ambient temperature. See Tables 2-8 through 2-11 of the PSD permit application, dated August 1999.

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Pipeline quality natural gas burned in CC-1 combustion turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.041**	5. Maximum Annual Rate: **9,122.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,040**
10. Segment Comment (limit to 200 characters): **Maximum hourly and annual fuel rates based on 1,083.0 mmBtu/hr heat input and a nominal natural gas heat content of 1,040 Btu/ft^3.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate fuel oil burned in CC-1 combustion turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **8.179**	5. Maximum Annual Rate: **8,178.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **137**
10. Segment Comment (limit to 200 characters): **Maximum hourly and annual fuel rates based on 1,120.5 mmBtu/hr heat input and a nominal distillate fuel oil heat content of 137,000 Btu/ft^3.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	**025**		**EL**
2 – CO			**EL**
3 – PM			**EL**
4 – PM10			**EL**
5 – SO2			**EL**
6 – VOC			**EL**

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **166** lb/hour **133.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **166 lb/hr** Reference: **Condition E.12 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on permit allowable rate for oil-firing.** **Annual emission rate based on permit cap for CC-1.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd @ 15% O_2, 720 block hour average**	4. Equivalent Allowable Emissions: **32** lb/hour **133** tons/year
5. Method of Compliance (limit to 60 characters): **NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Limit applicable for natural gas-firing.**	

Pollutant Detail Information Page 2 of 12

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **32 lb/hr**	4. Equivalent Allowable Emissions: **32** lb/hour **133** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial test only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd @ 15% O_2, 720 block hour average**	4. Equivalent Allowable Emissions: **166** lb/hour **133** tons/year
5. Method of Compliance (limit to 60 characters): **NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Limit applicable for distillate fuel oil-firing.**	

Pollutant Detail Information Page 3 of 12

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **166 lb/hr**	4. Equivalent Allowable Emissions: **166** lb/hour **133** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial test only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Limit applicable for distillate fuel oil-firing.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **43** lb/hour **188.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **43 lb/hr** Reference: **Condition E.13 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**

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

Hourly emission rate based on permit allowable rate.

Annual emission rate based on continuous operation:
Annual CO = (43 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 188.3 ton/yr

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **43** lb/hour **188.3** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 10 (annual, gas-firing only) or submittal of periodic tuning data.

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

FDEP Rule 62-212.400, F.A.C.
Limit applicable for both natural gas- and distillate fuel oil-firing.

Pollutant Detail Information Page 5 of 12

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **43 lb/hr**	4. Equivalent Allowable Emissions: **43** lb/hour **188.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (annual, gas-firing only) or submittal of periodic tuning data.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400, F.A.C.** **Limit applicable for both natural gas- and distillate fuel oil-firing.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10** lb/hour **24.4** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10 lb/hr** Reference: **Condition E.16 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**

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

Hourly emission rate based on permit allowable rate for distillate fuel oil-firing.

Annual emission rate based permit limits and on 7,760 hr/yr natural gas-firing and 1,000 hr/yr distillate fuel oil-firing:

Annual PM/PM_{10} = ([5 lb/hr x 7,760 hr/yr] + [10 lb/hr x 1,000 hr/yr]) x (1 ton / 2,000 lb)
Annual PM/PM_{10} = 24.4 ton/yr

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **5 lb/hr**	4. Equivalent Allowable Emissions: **5** lb/hour **24.4** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 9 (surrogate for PM/PM_{10})
Annual test only for fuel oil and only if fuel oil is combusted for more than 400 hours during a 12-month period.

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

FDEP Rule 62-212.400, F.A.C.
Limit applicable for natural gas-firing.

Pollutant Detail Information Page 7 of 12

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **24.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9 (surrogate for PM/PM_{10})** **Annual test only for fuel oil and only if fuel oil is combusted for more than 400 hours during a 12-month period.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400, F.A.C.** **Limit applicable for distillate fuel oil-firing.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.5** lb/hour **9.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **4.5 lb/hr** Reference: **Condition E.14 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on permit allowable rate for oil-firing.** **Annual emission rate based permit limits and on 7,760 hr/yr natural gas-firing and 1,000 hr/yr distillate fuel oil-firing:** **Annual VOC = ([1.8 lb/hr x 7,760 hr/yr] + [4.5 lb/hr x 1,000 hr/yr]) x (1 ton / 2,000 lb)** **Annual VOC = 9.2 ton/yr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.4 ppmw**	4. Equivalent Allowable Emissions: **1.8** lb/hour **9.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 18, 25, or 25A (initial test only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.8 lb/hr**	4. Equivalent Allowable Emissions: **1.8** lb/hour **9.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 18, 25, or 25A (initial test only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **4.5** lb/hour **9.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 18, 25, or 25A (initial test only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Limit applicable for distillate fuel oil-firing.**	

Pollutant Detail Information Page 10 of 12

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **4.5 lb/hr**	4. Equivalent Allowable Emissions: **4.5** lb/hour **9.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 18, 25, or 25A (initial test only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-4.070(3), F.A.C.** **Limit applicable for distillate fuel oil-firing.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **57.4** lb/hour **35.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.05 weight % sulfur fuel oil** Reference: **Condition E.15 of FINAL Permit Revision No.: 0010005-003-AV**	7. Emissions Method Code: **0**

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

Hourly emission rate based on permit allowable sulfur content of distillate fuel oil.
Hourly SO_2 = (0.05 lb S/100 lb oil) x (57,400 lb oil/hr) x (2 lb SO_2/lb S) = 57.4 lb/hr SO_2

Annual emissions based on 1.6 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 57.4 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.
Annual SO_2 = ([1.6 lb/hr x 7,760 hr/yr] + [57.4 lb/hr x 1,000 hr/yr]) x (1 ton / 2,000 lb)
Annual SO_2 = 35.0 ton/yr

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Pipeline-quality natural gas**	4. Equivalent Allowable Emissions: **1.6** lb/hour **35.0** tons/year

5. Method of Compliance (limit to 60 characters):
40 CFR Part 75 Appendix D procedures

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

FDEP Rule 62-204.800(7), F.A.C.
Unit is also subject to less stringent SO_2 limits of 40 CFR Part 60, Subpart GG (NSPS).
Limit applicable for natural gas-firing.

Pollutant Detail Information Page 12 of 12

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **57.4** lb/hour **35.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-204.800(7), F.A.C. Unit is also subject to less stringent SO_2 limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for distillate fuel oil-firing.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Rule 62-212.400, F.A.C.** **Annual test only for fuel oil and only if fuel oil is combusted for more than 400 hours during a 12-month period.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

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: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): * **Best operational practices to minimize emissions and duration.** **Excess opacity allowed for startups, shutdowns, malfunctions, and fuel switching.** **Maximum period of excess emissions allowed is two hours in any 24 hour period.** **Rule 62-210.700(1), F.A.C.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: **TECO** Model Number: **42C**	Serial Number: **42C-65766-350**
5. Installation Date: **10/03/2000**	6. Performance Specification Test Date: **05/24/2001**
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Data shown above is applicable to the main (HRSG) stack CEMS.**	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: **CO2**	2. Pollutant(s): **Carbon Dioxide**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: **Siemens** Model Number: **6E**	Serial Number: **N1-M8-0535**
5. Installation Date: **10/03/2000**	6. Performance Specification Test Date: **05/24/2001**
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Data shown above is applicable to the main (HRSG) stack CEMS.**	

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: **TECO** Model Number: **42D**	Serial Number: **42D-45580-274**
5. Installation Date: **10/03/2000**	6. Performance Specification Test Date: **05/24/2001**
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Data shown above is applicable to the bypass stack CEMS.**	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code: **CO2**	2. Pollutant(s): **Carbon Dioxide**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: **Siemens** Model Number: **6E**	Serial Number: **N1-M0-0591**
5. Installation Date: **10/03/2000**	6. Performance Specification Test Date: **05/24/2001**
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Data shown above is applicable to the bypass stack CEMS.**	

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

Supplemental Requirements

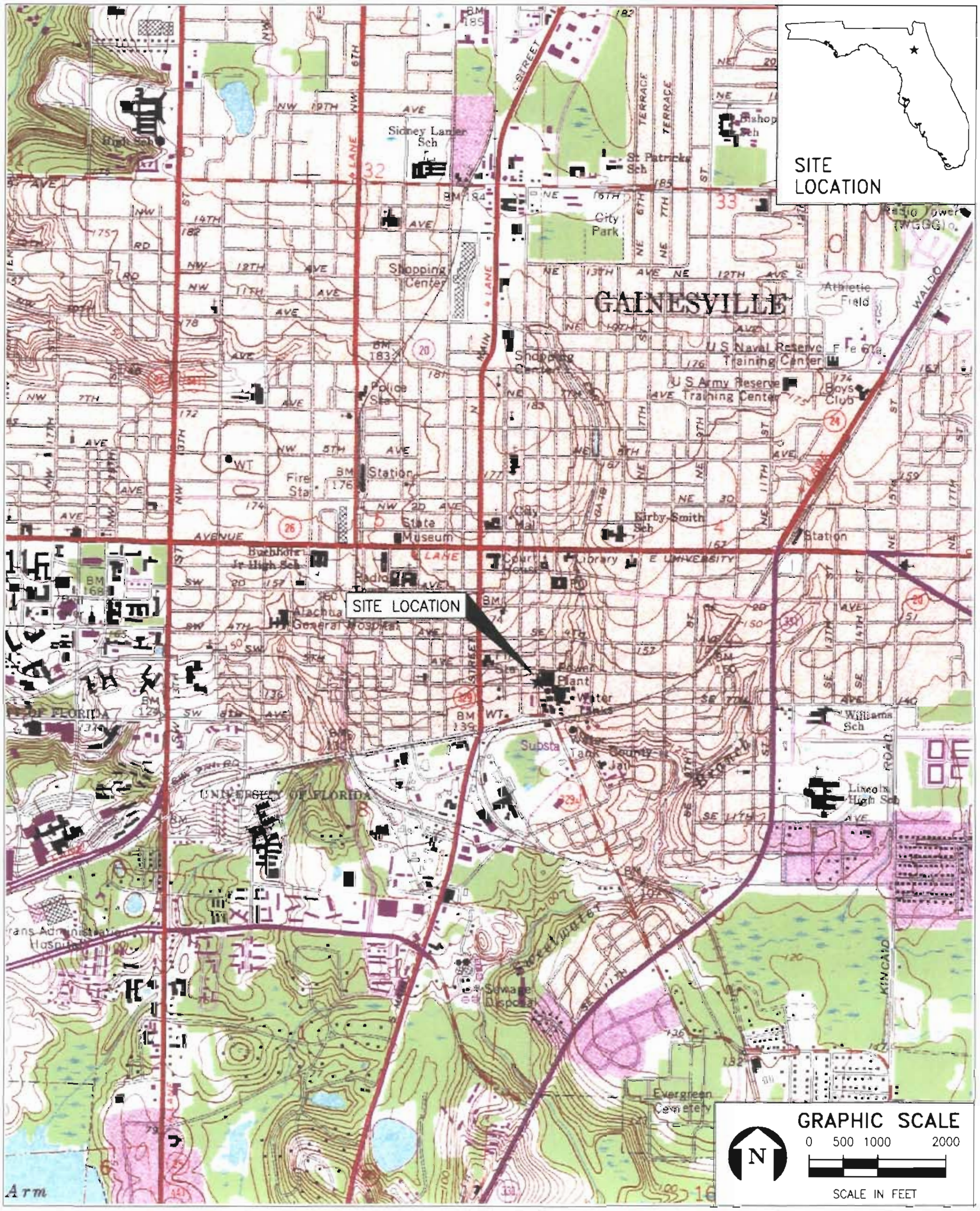
1. Process Flow Diagram [✔] Attached, Document ID: **DOC. II.C.3** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **DOC. III.J.2** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **DOC. III.J.3** [ ] Not Applicable [ ] Waiver Requested[
4. Description of Stack Sampling Facilities [✔] Attached, Document ID: **DOC. III.J.4** [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [✔] Previously submitted, Date: **March 2002** [ ] Not Applicable
6. Procedures for Startup and Shutdown [✔] Attached, Document ID: **DOC. III.J.6** [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [✔] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

DOC.II.C.1

AREA MAP



DOCUMENT II.C.1.

FACILITY LOCATION MAP

Source: USGS Quad: Gainesville East, FL, 1988; ECT, 2003.

GRU

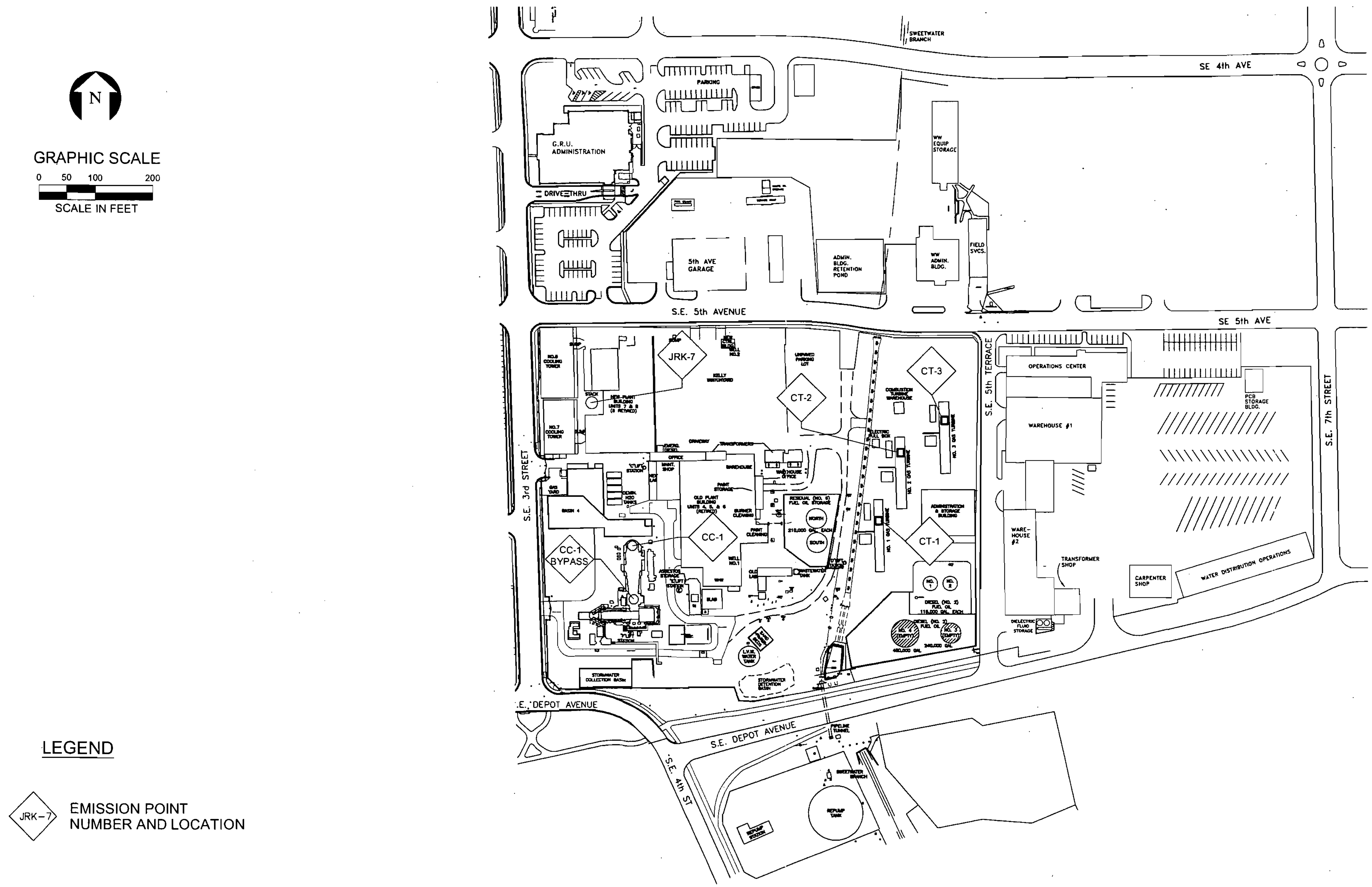
More than Energy

DOC.II.C.2

FACILITY PLOT PLAN

M:\ACAD\030413\GRU KELLY ECT

06/12/03 11:46 AM

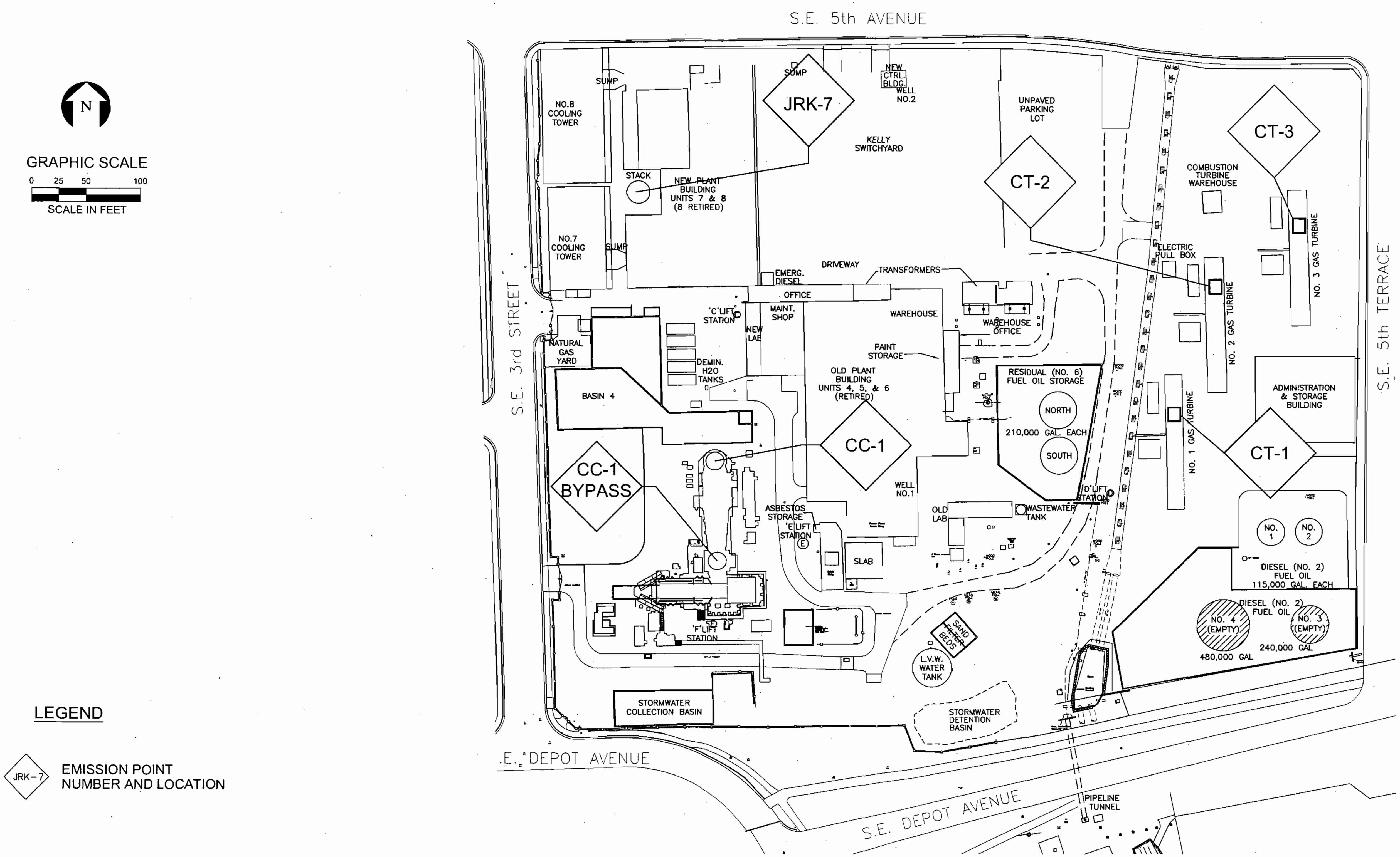


DOCUMENT II.C.2A.

FACILITY PLOT PLAN

Source: GRU, 2003.

GRU More than Energy



DOCUMENT II.C.2B.

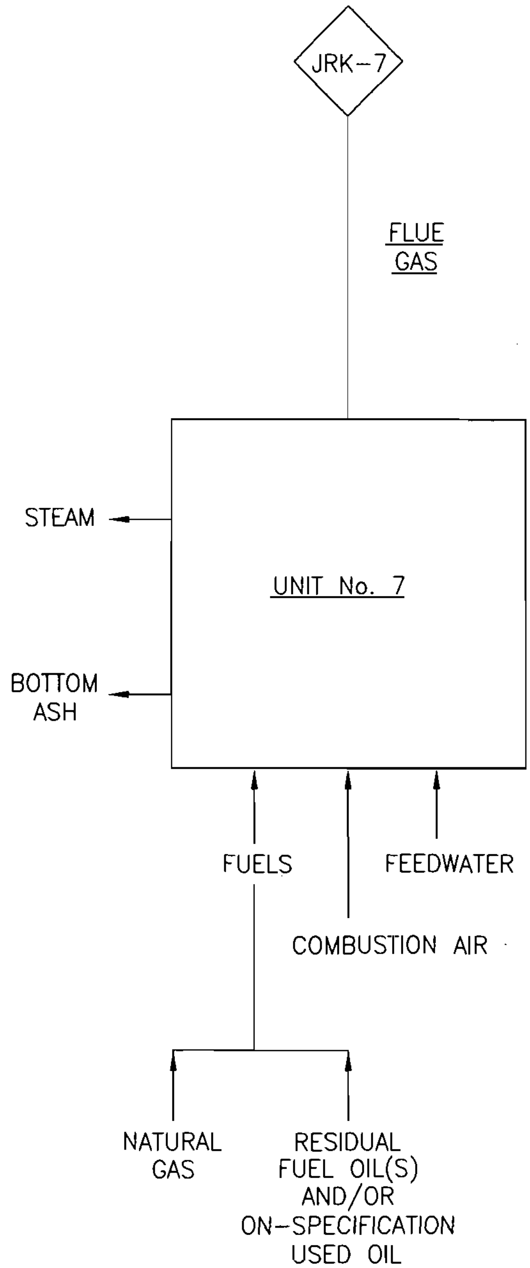
GENERATING STATION PLOT PLAN

Source: GRU, 2003.

GRU More than Energy

DOC.II.C.3

PROCESS FLOW DIAGRAM



DOCUMENT II.C.3A.

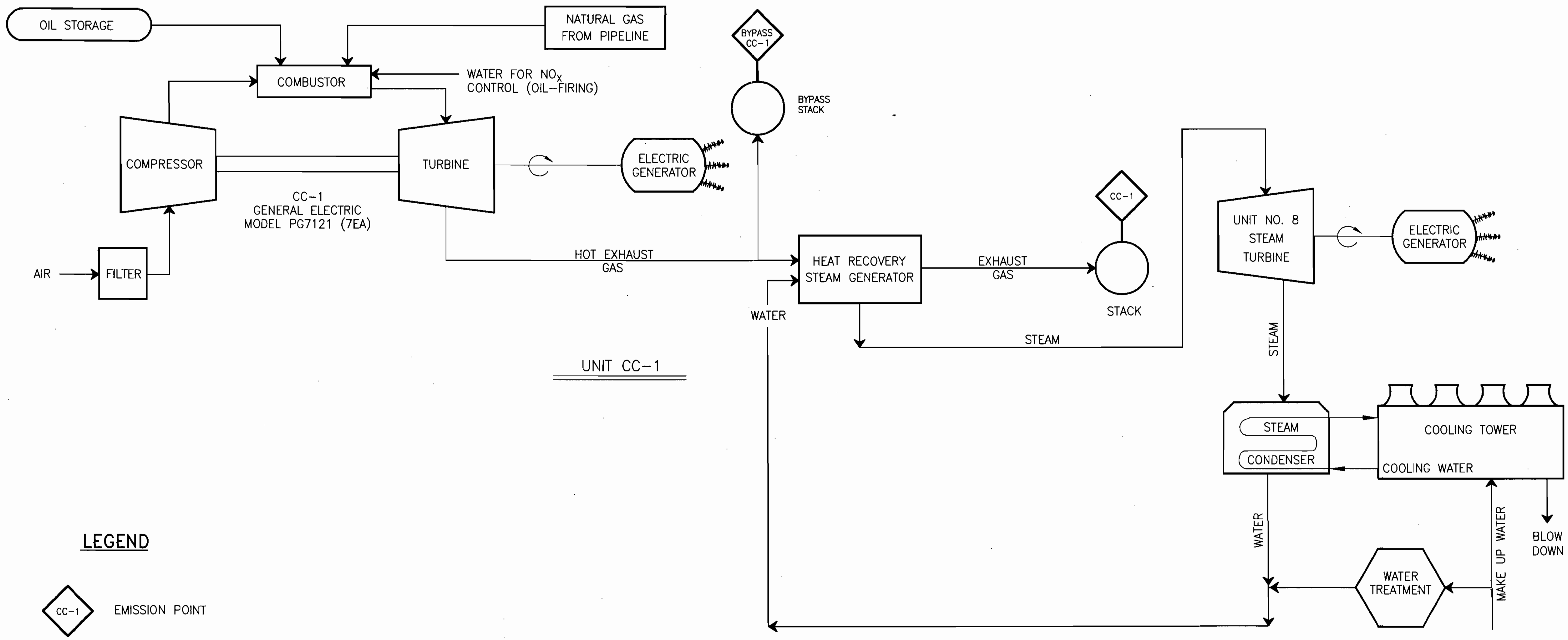
J.R. KELLY STATION

UNIT 7 PROCESS FLOW DIAGRAM

Source: ECT, 2003.

GRU[SM]

More than Energy[TM]



DOCUMENT II.C.3B.

J.R. KELLY STATION UNIT CC-1: PROCESS FLOW DIAGRAM

Source: ECT, 2003.

GRU More than Energy

DOC.II.C.4

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter (PM) emissions that may result from operations at the J.R. Kelly Generating Station include:

- Vehicular traffic on paved and unpaved roads;
- Wind-blown dust from material storage and yard areas; and.
- Periodic abrasive blasting

The following techniques may be used to control unconfined PM emissions on an as-needed basis:

- Paving and maintenance of roads, parking areas, and yards.
- Chemical (dust suppressants) or water application to:
  - Unpaved roads.
  - Unpaved yard areas.
  - Open stock piles.
- Removal of PM from roads and other paved areas to prevent reentrainment and from buildings or work areas to prevent airborne particulate.
- Landscaping or planting of vegetation.
- Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent PM.
- Confining abrasive blasting where possible.
- Enclosure or covering of conveyor systems.
- Other techniques, as necessary

DOC.II.C.8

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES

LIST OF PROPOSED
INSIGNIFICANT ACTIVITIES

<u>Brief Description of Emissions Units and/or Activities</u>

1. Internal combustion engines - mobile sources
2. Vacuum pumps for labs
3. Steam cleaning equipment
4. Lab equipment used for chemical or physical analyses
5. Brazing, soldering or welding equipment
6. One or more emergency generators located within a single facility provided:
   a. None of the emergency generators is subject to the Federal Acid Rain Program; and
   b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
7. One or more heating units and general purpose internal combustion engines, or other combustion devices, all of which are located within a single facility are not listed elsewhere in Rule 62-210.300(3)(a), F.A.C., and are not pollution control devices, provided:
   a. None of the heating units, general purpose internal combustion engines, or other combustion devices that would be exempted is subject to the Federal Acid Rain Program; and
   b. Total fuel consumption by all such heating units, general purpose internal combustion engines, and other combustion devices that would be exempted is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
8. Fire and safety equipment
9. Surface coating operation within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly, provided:
   a. Such operations are not subject to a volatile organic compound Reasonably Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.; and
   b. The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.
10. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
11. Space heating equipment (non-boilers)
12. Parts cleaning and degreasing stations not subject to 40 CFR 63, Subpart T.
13. Degreasing units using heavier-than air vapors exclusively, not subject to 40 CFR 63, Subpart T.
14. Storage tanks for residual fuel oils (Nos. 4, 5, or 6)/on-specification used oil or distillate fuel oils (Nos. 1 or 2)
20. Underground storage tanks for gasoline
21. Underground storage tanks for diesel
23. Turbine vapor extractors
24. Sand blasting and abrasive grit blasting

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES

25. Vehicle refueling operations
26. Freshwater cooling towers. The cooling towers do not use chromium-based treatment chemicals
27. Storage tanks less than 550 gallons
28. Architectural (equipment) maintenance painting
29. No. 2 fuel oil, residual fuel oils, and used oil truck unloading
30. Petroleum lubrication systems
31. Any other emissions unit or activity that:
    a. Is not subject to a unit-specific applicable requirement.
    b. In combination with other units and activities proposed as insignificant, would not cause the J.R. Kelly Generating Station facility to exceed any major source threshold(s) as defined by Rule 62-213.420(3)(c)1., F.A.C. unless acknowledged in a permit application.
    c. Would neither emit or have the potential to emit:
        i. 500 pounds per year of lead and lead compounds expressed as lead;
        ii. 1,000 pounds per year or more of any hazardous air pollutant;
        iii. 2,500 pounds per year or more of total hazardous air pollutants; or
        iv. 5.0 tons per year or more of any other regulated pollutant.

DOC.II.C.9

LIST OF EQUIPMENT/ACTIVITIES REGULATED UNDER TITLE VI

LIST OF EQUIPMENT/ACTIVITIES REGULATED UNDER TITLE VI

Equipment located at the J.R. Kelly Generating Station that contains more than fifty (50) pounds of charge of any Class I or Class II ozone depleting substance (ODS) regulated under Title VI of the Clean Air Act consists of one air conditioning (A/C) unit. Information regarding this A/C unit is provided as follows:

- Location—GRU Main Administration Building
- Refrigerant—R-1 1
- Amount of Refrigerant Charge—850 pounds

DOC.II.C.14 AND DOC.II.C.15

COMPLIANCE REPORT AND PLAN
COMPLIANCE CERTIFICATION

COMPLIANCE REPORT, PLAN, AND CERTIFICATION

1. Compliance Report and Plan

Appendix A to this Title V operation permit renewal application identifies the requirements that are applicable to the emission units that comprise this Title V source. Each emissions unit is in compliance, and will continue to comply, with the respective applicable requirements.

The emission units that comprise this Title V source will comply with future-effective applicable requirements on a timely basis.

2. Proposed Schedule for the Submission of Periodic Compliance Statements Throughout the Permit Term

Periodic compliance statements are proposed to be submitted on an annual basis consistent with FDEP Rule 62-213.440(3)(a)2., F.A.C. Compliance statement submittal date is proposed to be March 1st of each year consistent with the schedule required by 40 CFR §72.90 of the Acid Rain Program.

3. Compliance Certification

I, the undersigned, am the responsible official as defined in Chapter 62-210.200(220), F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete.

Randy L. Casserleigh
Interim Assistant General Manager
Energy Supply

6-23-03
Date

DOC.III.J.2

FUEL ANALYSES OR SPECIFICATIONS

FUEL ANALYSES OR SPECIFICATIONS
J.R. KELLY GENERATING STATION

A. No. 2 and Residual Fuel Oils

Specification	Units	No. 2 Fuel Oil CC-1	No. 2 Fuel Oil CT-1, CT-2, CT-3	Residual Fuel Oils
Heat Content	BTU/gal (min.)	137,000	137,000	150,000
Sulfur Content	Weight % (max.)	0.05	0.5	2.5
Ash Content	Weight % (max.)	0.05	0.05	0.1

B. Used Oil

Meets specifications of 40 CFR 279.11.

C. Natural Gas (typical composition)

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
Other Characteristics	
Heat content (HHV)	1,040 Btu/ft^3 at 14.73 psia, dry
Real specific gravity	0.5776
Sulfur content (maximum)	0.5 gr/100 scf

Note: Btu/ft^3 = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

DOC.III.J.3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

DETAILED DESCRIPTION OF POLLUTION PREVENTION EQUIPMENT

Combined/simple cycle unit CC-1 is equipped with dry low-NO_x (DLN) combustors and water injection to reduce the formation of NO_x emissions when firing natural gas and distillate fuel oil, respectively. Descriptions of these NO_x pollution prevention technologies are provided in the follow sections.

Dry Low-NO_x Combustor Design

A number of turbine vendors have developed DLN combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperatures are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical DLN combustor incorporates fuel staging using several operating modes as follows:

- Primary Mode—Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation.

- Lean-Lean Mode—Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 50 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.

- Secondary Mode (Transfer to Premix)—At 70-percent load, all fuel is supplied to second stage.

- Premix Mode—Fuel is provided to both stages with approximately 80 percent furnished to the first stage at turbine loads from 70 to 100 percent. Flame is present in the second stage only.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations. For CTGs capable of oil firing, water injection is employed to control NO_x emissions.

In addition to lean premixed combustion, CTG DLN combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All CTGs cool the high-temperature CTG exhaust gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the CTG turbine. By adding additional dilution air, the hot CTG exhaust gases are rapidly cooled to temperatures below those needed for NO_x formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO_x is reduced because the CTG combustion gases are at a higher temperature for a shorter period of time.

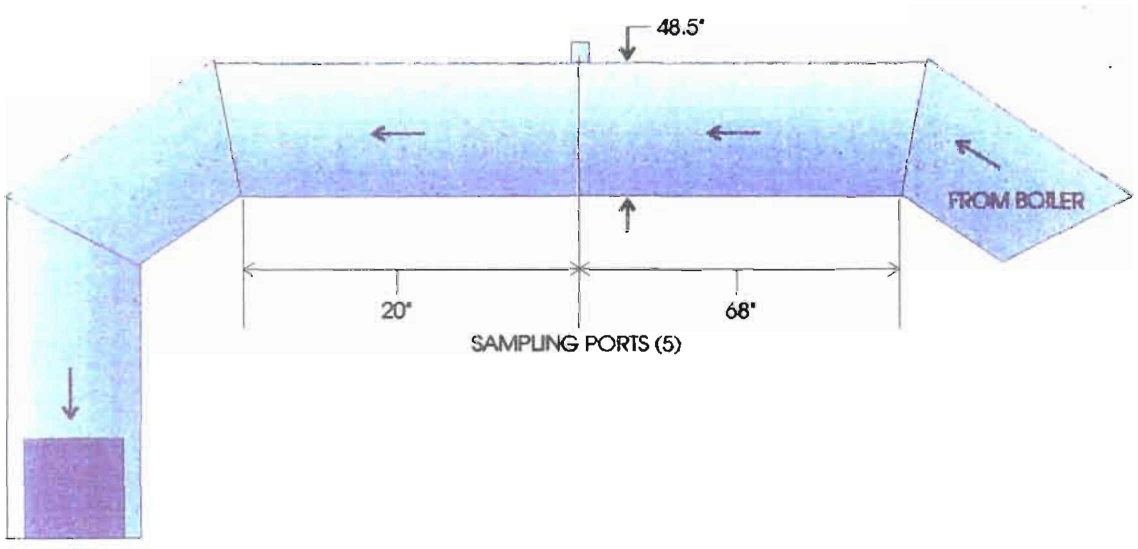
Water Injection

Injection of water into the primary combustion zone of standard combustors of a CTG reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Typical injection rates range from 0.3 to 1.0 pounds of water per pound of fuel. Water injection will not reduce the formation of fuel NO_x.

The maximum amount of water that can be injected depends on the CTG combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of water injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine.

DOC.III.J.4

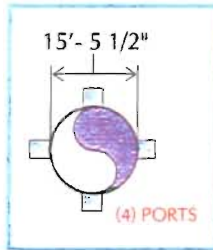
DESCRIPTION OF STACK SAMPLING FACILITIES



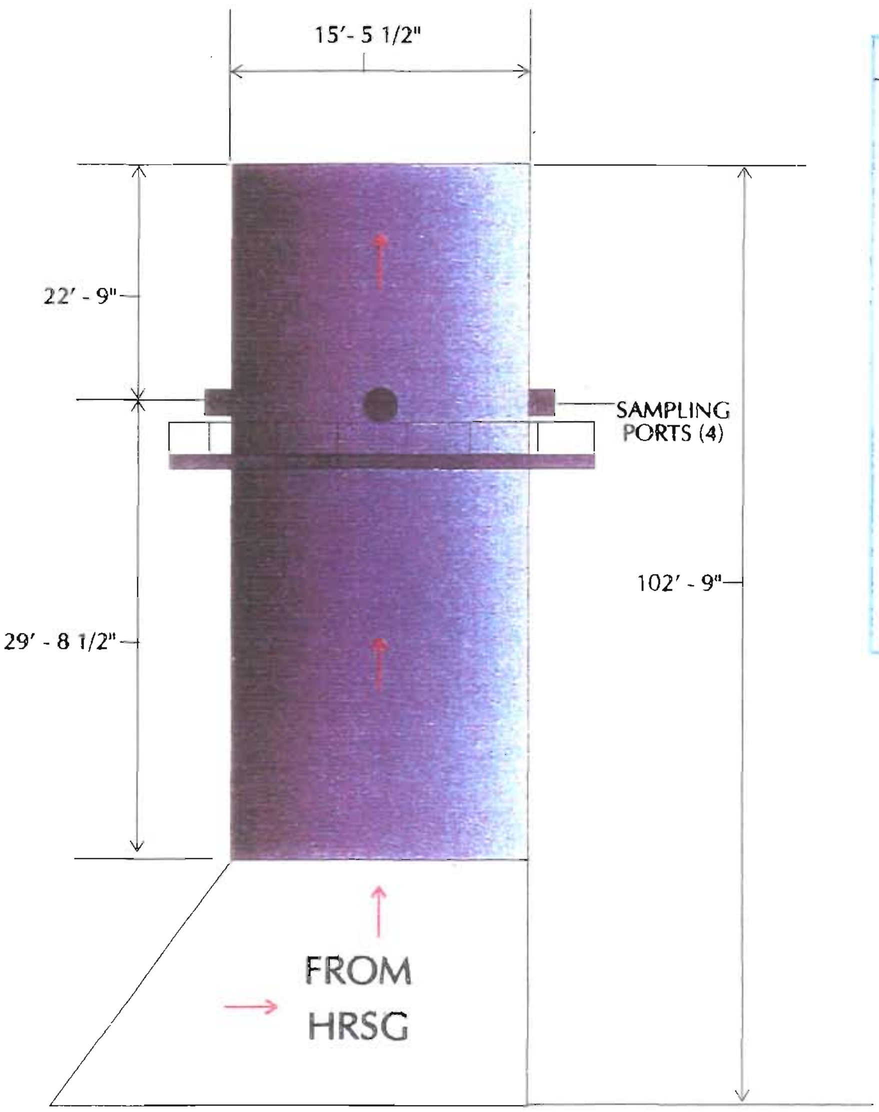
TRAVERSE POINT NUMBER	INCHES INSIDE STACK WALL
1	4.9
2	14.6
3	24.3
4	34.0
5	43.7

SOURCE: AIR CONSULTING & ENGINEERING, INC. (KELLY8) 4/12/02

FIGURE 1.
SAMPLING POINT LOCATION
GAINESVILLE REGIONAL UTILITIES
J. R. KELLY PLANT - UNIT 7
GAINESVILLE, FLORIDA



TRAVERSE POINT NUMBER	INCHES INSIDE STACK WALL
1	2.0
2	5.9
3	10.2
4	14.7
5	19.5
6	24.5
7	29.9
8	36.0
9	42.7
10	50.5
11	59.9
12	73.8



NOTE: NOT TO SCALE.

SOURCE: AIR CONSULTING & ENGINEERING, INC. (KELLYCC1) 7/5/01

FIGURE 1.
SAMPLING POINT LOCATION
J.R. KELLY GENERATING STATION - UNIT CC-1
GAINESVILLE REGIONAL UTILITIES
GAINESVILLE, FLORIDA

DOC.III.J.6

PROCEDURES FOR STARTUP AND SHUTDOWN

PROCEDURES FOR STARTUP AND SHUTDOWN
J.R. KELLY GENERATING STATION
UNIT NO. 7

GENERATING UNIT STARTUP

- Ensure all fluid levels are in limits.
- Insure fuel inventory is adequate.
- Ensure all fuel safety systems are in service.
- Ensure all valves/switches/breakers are set for startup.
- Establish fire in steam generator.
- Regulate firing rate to raise pressure and temperatures within established limits.
- At approximately 800 psig and saturation temperature +75 degrees Fahrenheit, begin steam admission to turbine.
- Increase turbine speed and firing rate in accordance with established operating limits until turbine speed reaches approximately 3,600 rpm.
- Synchronize generator to power grid and increase generator load to 5 percent.
- Ensure all required systems are in service and operable.
- Increase generator load to desired operating level.

GENERATING UNIT SHUTDOWN

- Reduce generator load and reduce pressure and temperature to established levels.
- Open generator breaker(s) to disconnect generator from power grid.
- Reduce fuel flow to minimum and trip fuel.
- Secure all operating and safety systems in accordance with established operating procedures.

PROCEDURES FOR STARTUP AND SHUTDOWN
J.R. KELLY GENERATING STATION
UNIT NO. 7

STARTING SEQUENCE

Upon receiving the startup signal from the plant control system, the turbine will proceed automatically through the following sequence:

1. Lube oil pump starts.
2. Compressor for clutch air starts and clutch is engaged.
3. Turning gear starts.
4. Starting device runs and accelerates from low speed. Turning gear shutdown at 20-percent speed.
5. At about 20-percent speed, the ignition is turned on and fuel is injected. The machine accelerates to approximately 55-percent speed; starting device clutch disengages and starting device shuts down.
6. The unit is run at 95-percent speed for the required warmup period and then accelerated to synchronous speed.

SHUTDOWN SEQUENCE

1. The unit runs for the required length of time at idle speed to assure proper cool down.
2. A relay turns the control switch to off and fuel is shut down. The lube oil pump starts at approximately 80-percent speed and the machine continues deceleration.
3. Clutch is engaged.
4. The turning gear starts and drives machine spindle for completion of the cooling off period.
5. The clutch is disengaged and turning gear and lube oil pump shut down.

PROCEDURES FOR STARTUP AND SHUTDOWN

UNIT CC-1

<u>CCI HOT START UP</u>

NOTE: at this time it is important that the instrument air lines at CT04 be blown down prior to gas turbine start up

1. Place 8CW-LC-140 (hot-well level control bypass) in auto
   a. bypass vacuum de-aerator on 2nd floor (only if necessary)
2. Change rotary instrument air compressor to city water
2. Start 30hp lube oil pump, ensure the 7.5 hp L.O. pump shuts down (place The 30hP in auto)
4. It is best if pressure de-aerator and hot-well are ~3" or lower
5. At ~5-8 minutes before the hour start CT04
   a. CT04 should not fire before the hour
   b. This is done to avoid a 1-hour NOX exceedance in a short CEMS operating hour (any hour in which CT04 combusts fuel for more than ~30 seconds is a CEMS operating hour
   c. the CT04 may be fired at 16 minutes after the hour if required (i.e. warm start up) this means you may have a fire in CT04 at 16 minutes after the hour therefore allowing you and additional 44 minutes for unit start up
6. When a flame is detected at all the primary flame detectors on CT04 and CT04 exhaust temperature is > the HRSG inlet temperature, open the HRSG stack damper fully and the bypass stack damper to ~85%
   *Note: once the CEMS monitor indicates the bypass stack is active, the bypass stack damper must remain at <89% open for ~40 minutes, until the bypass stack CEMS calibration is complete and recorded in the CEMS daily log
7. Begin opening the HP sky valve (MS-MOV-117) to establish flow through the boiler **<u>after</u>** H.P. steam pressure has started to increase
   a. H.P. sky valve ~45% and L.P. sky valve ~25%
      1) the percentages will vary according to the pressure ramp rate
   b. open MS-MOV-105 and place in auto (main steam header drain)
   c. open MS-MOV-141 if conditions warrant
      1) this valve may be opened later or even cycled if necessary
      2) if opened a second circulating pump should be started
      *Note: 141 is used to raise temperature at the throttle in order to roll the steam turbine. It may be opened early in the start up or later according to each individual fireman and the proximity of turbine metal temperatures to throttle temperature
   d. Allow HP drum pressure to increase slowly, monitor HP steam pressure ramp rate, use the sky valve to moderate within limits
8. If there is a 25F superheat at the throttle inlet, start to pull vacuum on #8 (ensure there is a 25F superheat not only at the throttle but also at the sky valve as well to ensure a true reading)
   a. start a condensate pump; close the vacuum breaker
   b. open DW-MOV-101 (domestic water to gland seal condenser eductor)
   c. place CW-LCV-107 in auto (gland seal tank level control valve)

d. open CW-MOV-113 (gland seal water block valve)
e. place CW-PCV-110 in auto (gland seal water pressure control valve)
f. open CW-MOV-112 (gland seal steam and throttle valve leak off condensers supply water)
g. open MS-MOV-104 (gland seal steam supply valve)
*Note: at this time it is necessary to open the gland seal steam root valve
h. start both vacuum pumps
*Note: in order to start a vacuum pump a make up and a circulating pump must be running, and the vacuum breaker must be closed to atmosphere
i. start cooling tower fans and run in high
j. start a second circulating pump if not running already
k. start a condensate re-circulation pump and place condensate pre-heater control valve in auto

9. When possible place CT04 in auto synch mode and tie on line. Pick up load to about ~16 MWs and 1-2 MVARs (~20-25 minutes after CT04 is fired)
*Note: ensure that Pre-select load has been selected

10. When turbine inlet pressure is ~550# and throttle steam temperature is >610F you may latch up and begin to roll #8 turbine
a. if point 12 is 50F < point 13 then latch up turbine and begin to roll #8
b. if point 12 is over 50F < point 13
1) wait until point 12 is within 50Fof point 13
c. or you may go to Manual Speed control and place control to manual
*Note: step c is for emergency use only at this time and the throttle pressure must be >400# in order to bypass and roll unit up manually
1) ensure turbine trip is reset
2) go to throttle valve demand station and open to ~30-40%
3) when speed has increased to 100rpm, place speed control in auto and continue to roll unit using the ATS start up
d. ATS start up procedure:
1) ensure turbine trip is reset
2) place ATS select in auto
3) at acceleration rate rpm/min select fast speed
4) select throttle valve to be used
5) give ATS hold a go
6) place synch in auto
e. close MS-MOV-141 at this time
f. secure turning gear after unit has rolled off
11. Slowly begin to place spray attemperation in; ~2 % increments until ~25-30% A feed water pump has to be started prior to this and main steam flow must be > 50,000 lbs/hr
12. If CEMS calibrations on the bypass stack are complete and it has been 40 minutes since the bypass stack went active on the CEMS monitor, CT04 is now released to the fireman

a. at approximately 5-10 minutes till the hour select base load on CT04 and select VAR control with a set-point of ~10MVARs
   1) if unit is started later, the time will have to be adjusted
b. close the bypass stack damper to 30-40%. Open bypass stack when needed (i.e. when the pressure ramp rate begins to decrease) Monitor pressure ramp rate, adjust H.P. sky valve as needed

*Note: temperature will increase sharply as CT04 goes through lean-lean to pre-mix, it will be necessary to spray during this time, but when the unit is at pre-mix steady state and exhaust temperature is ~1010 to 1020F the spray should be roughly 20-30% or lower until #8 turbine is loaded

13. Maintain HP drum level at ~15-20" low and the LP drum at ~10" low
    a. when starting a feed-water pump for the first time, ensure that the warm up valves on both pumps are open (FW-MOV-146 and 147). Also ensure that the re-circulation valve associated with the pump started opens completely prior to the pump starting and shuts when the discharge valve begins to open
    b. place in auto with HP feed-water valve set-point at –18" and LP feedwater valve set-point at –12"

*Note: suction flow must be maintained above 50,000 lbs/hr to prevent the feed-water pump from tripping on low flow (<40,000 lbs/hr for 60 seconds or 30,000 lbs/hr for 15 seconds)

14. Turbine speed should increase through the critical points and through the soak points as long as turbine metal temperatures are within limits
15. When turbine speed is ~3200rpm and main oil pump discharge pressure is >125#, ensure the 30Hp lube oil pump shuts down
16. Closely monitor throttle inlet temperature at this point and spray accordingly
    a. temperature should be kept within controllable limits at this time

CAUTION: it is important that spray attemperation be placed in slowly to avoid damage to the super heater tubes. Care should be taken that when possible spray attemperation be placed into service as soon as possible to avoid high temperatures at the inlet to the turbine. High temperatures will cause the bypass stack damper to trip at 975F secondary super-heater outlet. It may necessary to close the bypass stack damper if temperature increase is approaching 970F and not controllable. Place spray attemperation in slowly and only in 2% increments! Monitor SH2 temperature to stay within limits

17. When turbine speed is ~3550rpm, place the voltage regulator in service

    *NOTE: when raising voltage, bring voltage up till voltages are matched at DCS as indicated on the auto synch page, continue to raise voltage until permissive check is not lit, lower voltage back down until voltages are matched again (this is to ensure MVAR load is on the lag side when unit comes on line)

    a. at the DCS open the auto synch page and verify voltages matched
    b. monitor this page for synchronization requirements until unit ties on line
18. Open the auto start page for #8 and ensure load picks up to ~2-3 MWs and ~1 MVAR after #8 ties on line
    a. ensure the H.P. – L.P. drum blow down valve (8MS-FCV-153) opens

19. Swap auxiliaries on #8 to station service
20. Slowly begin to ramp #8 to full load
    *Note: check the governor ramp rate on the unit master screen and ensure set-point is 25%/min
    a. monitor throttle inlet temperature
    *Note:The spray should be shut off gradually to maintain 950F at turb. inlet
    b. when MW load on #8 is 5-10 MWs begin to place LP steam to the cross-over pipe and start shutting off on the LP steam sky valve (open LS-MOV-111 for a few minutes prior to admitting steam to the crossover. When adequate flow has been established to the crossover, close LS-MOV-111 and 112) Begin placing pressure de-aerator pressure control valve LS-PCV-104 in with a set-point of ~10#. Maintain 25# on LP drum if possible
       *Note: it is imperative that the LP drum is at least 12" low when this is started to prevent tripping the LP steam to the crossover pipe block valve. Open LP stm to the crsovr & PCV-104 in unison with closing the LP sky valve, monitor the LP drum level while doing this do not allow the LP drum level to increase to 5" high or the block valve will trip. If the level is high it may be necessary to open LS-MOV-118 to drop the LP drum level to begin this procedure
    c. ensure the turbine, throttle, extraction, and MS-MOV-105 drains close and manually close the pressure de-aerator vent bypass at 5 MWs
    d. when #8 MW load is ~20 MW, start a second condensate pump
21. Slowly bring the HP drum level to zero by raising set point in 2" increments
22. When the LP steam to the crossover valve is >80% and the LP sky valve is fully closed, bring the LP drum level to zero by raising set point in 1-2" increments
23. Hot-well and pressure de-aerator levels may be hard to maintain during start up and may fluctuate over a wide margin. At this time begin adjusting level control valves to bring levels to 0" in both
24. Start the hydrazine and amine pumps at this time. Inform the lab and they will start the appropriate phosphate pumps. Open the LP drum blow-down valve ~4 turns Open the pressure de-aerator vent bypass valve

*Note: the number of turns to be opened may be changed from time to time by lab personnel and will have to be opened accordingly on the LP blow down

25. When make up flow rate has decreased and levels are near normal shut down starting make up pumps and shift to either the small or big make up pump. Also when possible, place vacuum de-aerator into service if bypassed

DFS/RTH 7/31/01

HEAT RECOVERY STEAM GENERATOR START UP

The following is an approximate start up procedure for the heat recovery steam generator (HRSG). They are not intended to be followed to the letter and may be deviated from according to the needs of the boiler. The main criteria to be followed during start up is limiting the rate of saturated steam temperature in the high pressure (HP) drum, until the HP drum saturation temperature is 400F the rate of increase is limited to 6.7F/minute. After reaching 400F saturated steam temperature in the HP drum the limitation is 3.3F/minute. The DCS has a ramp rate bar graph to monitor the H.P. boiler pressure increase. To control the pressure increase/decrease you may open/close the sky valve or lower/raise the bypass stack as needed.

It is also important to keep a watch on both L.P. drum level and HP drum level, especially when opening or closing the associated sky valve. Operation of the sky valve can have a dramatic affect on the level in that drum. Opening of the sky valve reduces the pressure and will allow drum level to rise (expand). The very opposite is true as well. With the low pressure inlet valve to the cross over pipe and the pressure de-aerator steam inlet valve, opening it and closing it will have the same affect on the LP drum as the sky valve.

It may be necessary to open or close MS-MOV-118 and LS-MOV-118 during start up to maintain drum levels. Close attention must be taken when opening them as the sky valve operation may increase the rate of decrease in drum levels.

After steam flow through the HP steam line is established through the sky valve, and MS-MOV-105 (main header drain) all HP drains should be placed in auto. LP drains should be placed in auto at start up and monitored for proper operation. MS-MOV-141 drains directly to #8 condenser and will have a drastic affect on exhaust hood temperature without adequate flow and a vacuum established. But, since opening 141 is necessary to raise turbine inlet temperature, it may be beneficial to start a second circulating pump during start up to aid in the removal of heat. Open auxiliary cooling water to plant equipment prior to starting. Also two closed cooling water pumps must be run when the closed cooling water system is placed into service to reduce motor amps as per E&I.

I. COLD START UP

1. Open MS-MOV-131 (HP drum vent) and place in auto

2. Open FW-TCV-138 (HPHT economizer bypass), 135, and 136 (#1 and #2 super-heater drains)
3. Open MS-PCV-117 (HP sky valve) to ~25%

   Note: allow HP drum pressure to increase to ~100# before slowly opening the sky valve. Use sky valve to maintain constant ramp rate for pressure increase

4. Open and place in auto MS-MOV-102 (throttle drain), 113 (turbine drain) and 105 (main header drain)
5. Open and place in auto LS-MOV-117 (LP drum vent)
6. Open LS-MOV-139 (superheater drain)
7. Place in auto LS-MOV-127, 136 and LS-LCV-130, and 133 (low pressure steam drains) 8LS-LCV-143 AND 8LS-LCV-144. The H.P. steam drains should be opened after pressure has been established and opened only momentarily then placed in auto.
8. Open LS-MOV-112 (LP outlet to crossover seat drain)
9. Open LS-PCV-105 (LP sky valve) to ~ 15%
10. Open LS-PCV-104 (LP steam to pressure de-aerator) to ~15%

*Note: allow LP drum pressure to increase to ~ 15# before opening the pressure de-aerator steam inlet or the sky valve. Use sky valve and de-aerator steam inlet to maintain pressure increase

11. Place in auto ES-FCV-101, 102,103, and 104 (extraction drains), should be open at this time
12. Ensure 8B-TCV-101 (domestic water to B/D tank) is in auto and setpoint is 140F. Ensure 8MS-FCV-153 (Hp to LP continuous b/d) is in auto (will open when #8 breaker is closed)
13. Place in auto CW-FCV-102, 104, and 106 (condensate discharge valves)
14. Ensure CW-FCV-109 is in auto (condensate recicrulation valve)
15. It is possible to place CW-LCV-133 and 109 in auto at this time but during start up may be necessary to place in manual to control levels (de-aerator level control valve and hotwell level control valve) Place MS-LCV-140 (hot-well level control bypass) in auto
16. Bypass vacuum dearator on 2nd floor (if needed)
17. Open FW-MOV-147 and 146 (feed water pump warm up valves)
18. Start up 30 Hp lube oil pump and shutdown 7.5 Hp lube oil pump Place both in auto
19. If CT04 has not run lately it will be necessary to start an aux. cool

water pump and 2 closed cooling water pumps (if not already running) and place one aux. pump in standby operation (check strainer dP)

20. Start a circulating pump on #8; vent condensers, place pH cell on pond water, place coupon rack in service, ensure acid mixing tee is open
21. Start a starting or the big make up pump at this time
22. If unit #8 is not already on turning gear do so now (#8 should be placed on turning gear as soon as possible prior to initiating a startup)

In order to simplify the procedure it is necessary to assume that CT04 is either at full speed no load or at base load. The exhaust temperature difference may run from ~750F at full speed no load to ~1010F at base load. The drastic difference will determine the degree that the bypass stack damper will be opened to the HRSG. At this time a large majority of start-ups are at full speed no load. Therefore the rest of the procedure is written with the assumption that the unit is at full speed no load. (If at all possible a cold start should not be done at base load). A pre-selected load of 16 MWs will give you an exhaust temperature of ~880F to 900F.

1. Verify CT04 exhaust temperature, it should be roughly 680-800F
2. HP drum level should be ~ -20" and LP drum level ~ -10" (if necessary open MS/LS-MOV-118 to blow down level in drums)
3. Open HRSG stack damper (verify full open position by limit switch indication at DCS)
4. Open bypass stack damper to ~20%. Watch temperature rise at the secondary super-heater gas inlet. Limit the temperature increase across the super-heaters until flow has been established through the HRSG. This can be accomplished by watching temperatures at various points along the gas path. Monitor the temperature rise at the HRSG stack. It may be necessary to close the bypass damper numerous times to limit the rise in temp at the super-heater tube area until flow is established throughout the HRSG
   - A. when bypass stack damper leaves full closed (or full open position) the seal air fan will shut down. Ensure the seal air fan restarts when the damper has reached a full open or shut position. Locally check seal air valve position.
   - B. start the amine and hydrazine pumps (may want to wait until a feed water pump is established and left one)

*Note: At this time there is no temperature rise limit on the super-heater. Caution will have to be taken when first opening the bypass stack damper on a cold start up to establish flow through the HRSG. Also it may be necessary to open the bypass stack damper more once the H.P. super heater metal temperatures have increased to ~500-600F to establish flow through the entire boiler.

5. When HP drum pressure begins to increase it should be monitored closely, the rise in pressure can be monitored on the ramp rate bar graph and may be controlled using the sky valve and/or the damper position.
6. Pressure will build at this time in both the HP and LP drums slowly. It is best to try and establish flow through the header by using the sky valves In the LP drum the LS-PCV-104 (press dear. steam inlet) may be used as well.
7. Ensure that MS-MOV-131 and LS-MOV-117 close when drum pressure in their perspective drums increases to HP-25# and LP-10#
   A. when the H.P. drum temperature is >325F, drum outlet temperature is >300F and temperature at the super-heater outlet is >300F 8MS-TCV-138 may be placed in auto and 135 and 136 may be closed.
   B. L.P. drum temperature should have at least 20F superheat if above Conditions are met and 8LS-MOV-139 can be closed at this time
      1. it may be necessary to leave139 open longer until enough steam flow is established across the L.P. super-heater section

Tie CT04 on line and bring to ~16mw at this time. (exhaust temp ~750-880F)

*Note: at this time it may be beneficial to open MS-MOV-141 to aid in bringing the turbine inlet temperature up, but a second circulating pump should be started to help reduce exhaust hood temperature. If needed, opening of this valve may be delayed until a vacuum is being pulled on #8.

8. To aid in establishing flow rate in the HP steam header it is possible to start pulling vacuum when you have a 25F superheat at the turbine inlet (gland seal steam is required to be >25F superheat before applying steam to seals) Throttle inlet steam pressure should be >350# prior to pulling vacuum.
9. At some point it will be necessary to start a feed-water pump to aid in controlling HP steam temperature or drum level control. A condensate pump will have to be started prior to this to establish flow to the mechanical seal coolers on the feed-water pumps.
   a. please note that if CT04 exhaust temperature is not greater than 975F it is not possible for the HP super-heater outlet temperature to increase above 975F and trip the bypass damper. Spray attemperation should be delayed until a few minutes prior to CT04 being brought up to base load

*Note: Suction flow rate must be maintained >50,000lbs/hr. If it should decrease to less than 40K for 60 seconds or <30,000lbs/hr for 15 seconds the pump will trip on low flow.

10. It is possible that when 50,000lbs/hr steam flow rate has been established on the HP steam header, that the spray attemperation to the HP secondary super-heater is begun to be put in. **CAUTION:** This is to be done slowly and in 2% increments only.

*Note: It is important that spray attemperation be place in slowly to avoid damage to the super heater tubes. High temperatures will cause the bypass stack damper to trip at 975F secondary super- heater outlet. It may be necessary for the bypass stack damper to be closed temporarily if temperature increase is approaching 970F and not controllable. Monitor the SH2 calc temperature to maintain at least a 25F difference between temperatures to ensure saturation temperature in the super heater is not approached.

11. When pulling vacuum on #8 steam turbine:

*Note: wait until throttle pressure is ~400#

a. open DW-MOV-101 to the condenser eductor
b. place CW-LCV-107 (gland seal tank level controller) in auto
c. open CW-MOV-113 (gland seal water block s/v)
d. place CW-PCV-110 (gland seal water pressure control valve) in auto
e. open CW-MOV-112 (gland seal steam/throttle valve leak off water s/v)
f. open MS-MOV-104 (at this time it is open and the gland seal steam root valve will have to be opened)
g. close MS-MOV-101 (vacuum breaker)
h. start both vacuum pumps and start all cool tower fans and run in fast

12. Ensure a vacuum begins to establish on the condenser over the next few minutes
13. When vacuum is established and turbine inlet pressure is >550# and turbine inlet temperature is >610F (at least 100F superheat at turbine) latch up turbine locally. Close MS-MOV-141 at this time.
14. At this point you may follow the #8 Steam Turbine Automatic Start Up at DCS procedure to tie the unit on line.

*Note: at approximately 2.5 hours after CT04 start up tie CT04 on line with

~16 MW and 1-2 MVAR. Allow to sit like this until ~10 minutes prior to request time and ramp unit up accordingly. This time is approximate and may be varied. Care should be taken at this time to control steam temperature and pressure increase.

15. After #8 is on line, and some load is initially placed on the unit, monitor drum, hot-well, and de-aerator levels. Begin to slowly move set-points towards normal operating levels.
    a. station auxiliaries should be read as soon as possible when units are placed on line and #8 auxiliaries swapped to station service as soon as the unit is on line

    *Note: for the drums the normal operating levels may not be zero inches and will be set according to boiler requirements and alarm status
16. Ensure MS-MOV-105 closes at ~5 MW.
17. At 5 MWs ensure that the extraction, turbine, and throttle drains shut completely. It may be necessary to place them in manual and shut them, then place them in auto. Close the press dear vent bypass.
18. Continue to load #8 while monitoring the turbine inlet pressure. When turbine inlet pressure drops to ~650# open some on the bypass stack damper. At this time this is not exact and will have to be watched closely until the governor and the bypass damper are fully open
19. During the loading open LS-MOV-111 and allow any condensation in the line to be removed to the condenser. Afterwards, slowly begin opening LS-PCV-124 to admit low-pressure steam to the crossover pipe. As you Open this valve; slowly begin to close off on the LP sky valve, while still Monitoring LP drum pressure. When the LP drum pressure is <40# Begin to close off completely on the LP sky valve and place in auto. After flow is established to the crossover you may close LS-MOV-111 And 112

*Note: the L.P. steam to the crossover cannot be placed into service until the unit is above 5 MW. Also it is best if the LP drum level is ~10" low before attempting to place steam to the crossover, as levels will rise considerably during this time.

20. When possible, and unit is stabilized, ensure the following valves are in auto: CW-LCV-109, CW-LCV-133, feed-water pump HP discharge valves FW-LCV-102 and/or 103, LP feed-water valve FW-LCV-129, yuba temperature control valves YW-TCV-103 and 105, HPHT #1 economizer bypass temperature control valve FW-TCV-138, and pond water to the lube oil coolers PW-TCV-123
21. Place 8RW-LCV-101 mode selector in auto (it may be necessary to place

7RW-LCV-101 in auto as well if cooling tower B/D is opened)

22. Open the L.P. blow-down ~4 turns (this number may change according to lab demands

DS/TH/WD/BD/DB/RL 2/28/02

HEAT RECOVERY STEAM GENERATOR SHUT DOWN

The following is an approximate shut down procedure for the heat recovery steam generator (HRSG). They are not intended to be followed to the letter and may be deviated from according to the needs of the boiler. The main criteria when shutting down is to maintain turbine inlet pressure above 500# in order to prevent the governor from going to a closed position. The bypass stack damper and the governor demand station will have to be operated in unison to maintain turbine inlet pressure. If at all possible increase hot-well level and pressure de-aerator level prior to shutdown. If this is not possible it may be necessary to bypass the vacuum de-aerator prior to shutdown to maintain adequate make up flow. Placing the hot-well level control bypass 8MW-LCV-140 in auto will assist in controlling levels. The turning gear motor is to be started prior to shut down to insure proper operation of it before the unit is off line. Ensure that the governor position ramp rate is set at 12 or above before beginning to ramp the unit down to ensure fluid decrease in load as the bypass damper is closed.

I. SHUTDOWN

1. Start turning gear motor on #8 turbine
2. Reduce governor demand station output to ~85%
3. Slowly begin closing LS-PCV-124 in 5% increments Monitor LP drum level and pressure do not allow pressure to increase above 50#. It may be necessary to open LS-PCV-104 to assist in maintaining LP drum pressure <50# (sky valve may be used as well)
   *Note: if the LP drum level is allowed to go </= to 20" the bypass damper will trip, if the drum level rises to >/= 5" the block valve to the cross over LS-FCV-110 will trip. Tripping of the block valve will have a drastic affect on LP drum level, compressing drum level due to the increase in LP drum pressure, and drum pressure, possibly lifting the drum safeties.
4. While monitoring turbine inlet pressure and reducing load allow turbine inlet pressure to increase to ~800# (monitor H.P. drum pressure)

5. At ~800# turbine inlet press pinch off the bypass damper to approximately 80%
6. Slowly begin to close off on FW-TCV-134 if open, do not allow HP secondary super-heater outlet temperature to increase to 975F or the bypass damper will shut. It may be useful to throttle the HP sky valve to maintain main steam flow to reduce steam temperature. Steam flow must remain > 50,000 klbs/hr to prevent the spray attemperation block valve from shutting prematurely

   *Note: This is not normally the case, but on extremely hot days there is a possibility that the attemperator valve may be open to control turbine inlet temperature
7. Monitor drum levels and feed-water pump suction flow rate, as well as hot-well and pressure de-aerator levels while reducing load on the governor demand station
   A. bringing pressure de-aerator and hot-well levels down to -1-2"low will help later on
   B. start a second make up pump at this time if necessary
8. Continue to reduce load and monitor turbine inlet pressure. If pressure rises to >800# close off on bypass stack damper to ~60%. It will be necessary to reduce bypass stack damper to 40% if pressure continues to rise while reducing load on governor demand station
9. Continue to monitor turbine inlet temperature
10. Allow pressure and MW load to reduce slowly at this point, it may be necessary to reduce load at the governor demand station to maintain turbine inlet pressure above 500#.
11. When turbine inlet pressure begins to rise close the bypass damper to 20% (do not close damper <20% it may cause damage to the damper seals and/or baffles in HRSG)
12. Begin to slow down cooling tower fans at this time
13. Caution should be taken at this time to monitor LP drum pressure and it may be necessary to reopen the LP sky valve to limit pressure to <50# or to help maintain LP drum level
14. Begin reducing MVAR load at this time to ~1MVAR
15. When <5MWs open the extraction steam drain valves, throttle, turbine, before and after seat LP cross-over drains (place valves in manual at at DCS prior to opening)

*Note: the LP steam to the cross over must be out by 5 MW or the block valve will trip automatically

16. When at ~3 MW close the bypass stack damper completely (-5%) and if not already closed the FW-TCV-134 to –5% and close FW-

MOV-133 (ensure bypass seal air fan starts when bypass is closed)

17. At ~2 MW ensure MVAR are at zero and trip steam turbine at DCS panel
    a. remove the voltage regulator from service and open the field breaker
    b. match flags on auxiliary breakers
18. Close HRSG stack damper
19. Turn off cooling tower fans and shutdown 2nd circulating water pump
20. Shutdown vacuum pumps
21. Begin bringing HP drum to ~0" and LP drum to ~2" high
22. When possible shutdown feed-water pump, close warm up valves at this time
23. Bring hot-well level and pressure de-aerator levels to ~0-3"low
24. At ~1800rpm place CW-PCV-110 and 113 in manual and close Allow gland seal tank level to return to normal and place CW-LCV-107 in manual and close
25. When at ~300rpm open vacuum breaker
26. When exhaust gauge at the turbine gauge board reaches zero close MS-MOV-104 (gland seal steam valve) *Note: at this time it is necessary to close the gland seal steam root valve
27. Close CW-MOV-112 (condensate block to steam condensers) and DW-MOV-101 (domestic water to condenser eductor)

*NOTE: allow CW-MOV-112 to close fully prior to closing DW-MOV-110

28. Shutdown condensate re-circulation pump and place CW-TCV-122 to manual and close to –5%
29. Shut down the condensate pump(s) at this time if possible, ensure the standby pump is placed in off prior to stopping last running pump
30. Place LS-MOV-111 in manual and close to prevent high tem-eratures in the exhaust hood area
31. When unit coasts down to zero speed, place turbine on turning gear
32. Ensure 7.5 Hp lube oil pump is in auto. Place 30 Hp lube oil pump in manual and shutdown. Ensure the 7.5 Hp starts and the unit remains on turning gear. Place 30Hp Lube oil pump in auto.
33. Shutdown amine, phosphate, and hydrazine pumps
34. Close LP and H.P. drum blow down valves completely
35. Shut-down make up pump(s)
    *Note: if CT04 is on oil, a starting make up pump must be left running for liquid fuel operations
36. If requested by system dispatch at this time, shut down CT04
    A. ensure the unit shuts down normally and goes on cool down

B. acknowledge any CEMS alarms

38. Log all off line times and enter all data into service records

DS/TH/WD
5/17/01

DOC.III.J.11

ALTERNATE METHODS OF OPERATION

ALTERNATIVE METHODS OF OPERATION
J.R. KELLY GENERATING STATION

Unit No. 7 - Fossil Fuel Steam Generator

Method No.	Fuel Type	Fuel Sulfur Content (Wt %)	Heat Input Range (MMBtu/hr)	Maximum Operating Hours (Hrs/Dy)	(Dys/Wk)	(Hrs/Yr)
1	Natural Gas	N/A	0 - 272.0	24	7	8,760
2	Residual Fuel Oil/Used Oil	2.5	0 - 249.0	24	7	8,760
3	Co-firing Natural Gas/ Residual Fuel Oil/Used Oil	N/A 2.5	0 - 272.0	24	7	8,760

Simple Cycle Combustion Turbines CT-1, CT-2, and CT-3

Method No.	Fuel Type	Fuel Sulfur Content (Wt %)	Heat Input Range (MMBtu/hr)	Maximum Operating Hours (Hrs/Dy)	(Dys/Wk)	(Hrs/Yr)
1	Natural Gas	N/A	0 - 200.0	24	7	8,760
2	No. 2 Fuel Oil	N/A	0 - 207.0	24	7	8,760

ALTERNATIVE METHODS OF OPERATION
J.R. KELLY GENERATING STATION

Combined/Simple Cycle Combustion Turbine CC-1

Method No.	Fuel Type	Fuel Sulfur Content (Wt %)	Heat Input Range (MMBtu/hr)[1]	Maximum Operating Hours		
				(Hrs/Dy)	(Dys/Wk)	(Hrs/Yr)
1	Natural Gas	N/A	0 – 1,083	24	7	8,760
2	No. 2 Fuel Oil	N/A	0 – 1,121	24	7	1,000

[1] Upper range of loads shown are at 100% load, 20°F, 14.7 psia, and 60% relative humidity conditions.

DOC.III.J.15

ACID RAIN PART APPLICATION

GRU
GAINESVILLE REGIONAL UTILITIES
STRATEGIC PLANNING

January 29, 1999

via fax 850/922-6979

Tom Cascio
Dept. of Environmental Protection
2600 Blair Stone Road, Mail Station 5505
Tallahassee, FL 32399-2400

Re: Phase II Permit Application
J. R. Kelly Generating Station

Dear Mr. Cascio:

As discussed in our telephone conversation, enclosed is the Phase II Permit Application for J. R. Kelly Repowered unit.

If you have any questions, please contact me at (352) 334-3400 ext. 1284.

Sincerely,

Yolanta E. Jonynas/gm

Yolanta E. Jonynas
Sr. Environmental Engineer

Encl.

xc: Randy Casserleigh
Darrell DuBose
Gary Swanson
JRKCC

W:\U0070\ENV\JRK REPOWERING PHASE II PERMIT APPLICATION

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

Phase II Permit Application

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

This submission is: New ☐ ☒ Revised

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

Plant Name	State	ORIS Code
J. R. Kelly	FL	664.

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

a Boiler ID#	Compliance Plan b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Compliance Plan c Repowering Plan	d New Units Commence Operation Date	e New Units Monitor Certification Deadline
~~JRK8~~ CC1 *	Yes	NO	1/29/2001	Unknown
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

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

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

* Existing unit JRK8 will be repowered to a combined cycle unit via the addition of a combustion turbine and a heat recovery steam generator. The new unit will be designated as CC1 and will have a nominal capacity of 110 MW.

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

J. R. Kelly

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

re ·ed under the Acid Rain Program; and,

Plant Name (from Step 1)

J. R. Kelly

Recordkeeping and Reporting Requirements (cont.)

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

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

Liability.

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

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

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

Certification

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

Name	Randy L. Casserleigh

Signature	Date 1/29/95

STEP 5 (optional)
Enter the source AIRS and FINDS identification

AIRS	
FINDS	

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

VIA OVERNIGHT MAIL

June 21, 2001

U.S. Environmental Protection Agency
Acid Rain Program (6204N)
Attention: Designated Representative
633 3rd Street, NW
Washington, DC 20001

RE: Gainesville Regional Utilities
Deerhaven and J.R. Kelly
Certificate of Representation

Dear Sir or Madam:

Enclosed is (1) original Certificate of Representation for Gainesville Regional Utilities Deerhaven and J.R. Kelly generating stations.

An ad providing public notice of the Designated Representative appointment has been placed in the local newspaper and will run one day.

If you have any questions, please call me at (352) 334-3400 ext. 1284.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Senior Environmental Engineer

YEJ/srm
Enclosures

xc: Randy Casserleigh
Wilson Haynes, EPA Region 4
Jenny Jachim, EPA Region 4
Joe Kahn, FDEP, Tallahassee
Robert Klemans
Skip Manasco
Scott Sheplak, FDEP, Tallahassee
Joe Shaw
Gary Swanson
Donny Thompson
CAA/DR

BEST AVAILABLE COPY

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Certificate of Representation

Page 1

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☐ New ☒ Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 ☐

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

Plant Name	State	ORIS Code
J.R. Kelly	FL	664

STEP 2
Enter requested information for the designated representative.

Name	Randy L. Casserleigh
Address	Gainesville Regional Utilities P.O. Box 147117 (A132) Gainesville, FL 32614-7117
Phone Number	352-334-3400 Ext. 1789
Fax Number	352-334-2786
E-mail address (if available)	CasserleighRL@gru.com

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name	Gary P. Swanson
Phone Number	352-334-3400 Ext. 1707
Fax Number	352-375-2232
E-mail address (if available)	SwansonGP@gru.com

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1): J.R. Kelly

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

Signature (designated representative)	Date 6/20/01
Signature (alternate designated representative) Gary L. Swanson	Date 6/20/01

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name City of Gainesville, d.b.a. Gainesville Regional Utilities					[X] Owner	[X] Operator
ID# CC1	ID# JRK8	ID# **	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

** JRK8 is a retired unit under the Acid Rain Program

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

June 21, 2001

Mr. Scott Sheplak, Administrator
Title V Section
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station (Facility ID 0010005)
Deerhaven Generating Station (Facility ID 0010006)
Change in Responsible Official

Dear Mr. Sheplak:

Notice is hereby provided that effective immediately Mr. Randy L Casserleigh, Interim Assistant General Manager of Energy Supply, has been designated the responsible official (RO) for the above-referenced facilities pursuant to Rule 62-210.200(247). Mr. Casserleigh is also the Designated Representative for these facilities.

Please call me at (352) 334-3400 Ext. 1006 if you have any questions.

Sincerely,

Michael L. Kurtz

Michael L. Kurtz
General Manager

xc: D. Beck
R. Casserleigh
Y. Jonynas
C. Kirts, FDEP – Jax.
R. Klemans
S. Manasco
K. Pierce, EPA – Region 4
E. Regan
J. Shaw
G. Swanson
D. Thompson
CAA - DR
CAA - Title V JRK
CAA - Title V DH

JRKDHROdesignation601.y40

APPENDIX A

REGULATORY APPLICABILITY ANALYSIS

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 1 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	§60.7(b) - (h)		CC-1	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CC-1	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CC-1	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CC-1	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		CC-1	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CC-1	General procedures regarding reporting deadlines.
Subpart GG - Standard of Performance for Stationary Gas Turbines (recent amendments effective May 29, 2003)				
Standards for Nitrogen Oxides	§60.332(a)(1) and (b), (f), and (i)		CC-1	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		CC-1	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight (8,000 ppmw).

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines (continued)				
Monitoring Requirements	§60.334(a)	CC-1		Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ±5.0 percent. A NO_x CEMS is used to monitor for Subpart GG excess emissions in lieu of continuous monitoring of fuel consumption and ratio of water to fuel.
Monitoring Requirements	§60.334(b)(2) and (c)	CC-1		Requires periodic monitoring of fuel sulfur and nitrogen content. Sulfur sampling is not necessary for natural gas per EPA policy. Nitrogen sampling is only required if the nitrogen in fuel credit is taken; no credit is being taken for CC-1.
Test Methods and Procedures	§60.335		CC-1	Specifies monitoring procedures and test methods.
40 CFR Part 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978.		X		Standard applies to storage of petroleum liquids greater than 40,000 gallons. Subpart K §60.111(b) definition of petroleum liquids specifically excludes Nos. 2 through 6 fuel oils. Storage tanks greater than 40,000 gallons at the J.R. Kelly Station store No. 2 and No. 6 fuel oil and therefore are not subject to Subpart Ka.
40 CFR Part 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.		X		Standard applies to storage of petroleum liquids greater than 40,000 gallons. Subpart Ka §60.111a(b) definition of petroleum liquids specifically excludes Nos. 2 through 6 fuel oils. Storage tanks greater than 40,000 gallons at the J.R. Kelly Station Generating store No. 2 and No. 6 fuel oil and therefore are not subject to Subpart Ka.

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 Subpart Kb - Standards of Performance for Volatile Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.		X		All petroleum liquid storage tanks at the J.R. Kelly Generating Station were constructed prior to 7/23/84 and therefore are not subject to Subpart Kb.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts A, B, C, Cb, Cc, Cd, D, Da, Db, Dc, E, Eb, F, G, H, I, J, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS§ contain requirements that are applicable to the J.R. Kelly Generating Station. Subparts D, Da, and Db are not applicable because the steam boilers were constructed prior to August 17, 1971.
Regulations on Permits – Acid Rain Program	40 CFR 72. 1 through 6, 8, and 13		Unit No. 8	Covers retired unit exemption from the acid rain program.
Regulations on Sulfur Dioxide Allowance System	40 CFR 73		CC-1	SO2 allowance allocations listed in Table 2 of this regulation.
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CC-1	General Acid Rain Program requirements. SO_2 allowance program requirements started January 1, 2000.
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		CC-1	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CC-1	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. **(future requirement)**.
Permit Application Shield	§72.32		CC-1	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CC-1	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to Kelly Station Unit CC-1.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CC-1	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Fast-Track Modifications	§72.82(a) and (c)		CC-1	Procedures for fast-track modifications to Acid Rain Permits. (**potential future requirement**)
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CC-1	Requirement to submit an annual compliance report.
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A – General				
Prohibitions	§75.5		CC-1	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CC-1	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CC-1	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election was made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CC-1	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units, or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CC-1	CO_2 continuous monitoring requirements. Appendix G election was made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CC-1	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Certification and Recertification Procedures	§75.20(b)		CC-1	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CC-1	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CC-1	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CC-1	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CC-1	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		CC-1	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CC-1	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CC-1	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CC-1	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CC-1	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CC-1	Requirements pertaining to general recordkeeping.

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CC-1	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CC-1	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CC-1	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CC-1	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CC-1	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CC-1	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CC-1	Quarterly data report requirements.
Specific provisions for monitoring NOx and heat input for the purposes of calculating NOx mass emissions	§75.71		CC-1	Specifies methods to determine NOx emissions, which must not exceed the annual emission cap of 133 tons per year.
Determination of NOx mass emissions	§75.72		CC-1	Specifies methods to determine NOx emissions, which must not exceed the annual emission cap of 133 tons per year.

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CC-1	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CC-1	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CC-1	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		Kelly Station Unit CC-1 will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B		Vehicle Fleet Maintenance	Servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner is conducted by City of Gainesville staff who comply with Subpart B requirements.

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		The Kelly Station does not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Kelly Station will not produce any products containing ozone-depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Contractors maintain, service, repair, or dispose of any appliances in compliance with §82.154 prohibitions. Appliances are defined by §82.152 - any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Contractors technicians meet the certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		Contractors maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Compliance Assurance Monitoring		X		Program only applies to emission units which are equipped with control devices, excluding inherent process equipment.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 57, 58, 59, 67, 68, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 95, and 96		X		The listed regulations do not contain any requirements which are applicable to Kelly Station Unit CC-1.
40 CFR 279 – Standards and Management of Used Oil			Unit No. 7	Contains testing and recordkeeping requirements for incorporating used oil.+

Table A-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR 761- Polychlorinated Biphenyls (PCBs) Manufacturing, Processing, Distribution in Commerce, and Use Prohibitions			Unit No. 7	Specifies conditions necessary for burning PCBs in boilers.

Source: ECT, 2003.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040(1)(a), and (b), F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting procedures including filing in quadruplicate and required fees.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation with FDEP is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to the facility.
Modification of Permit Conditions	62-4.080, F.A.C	X			A Title V permit condition modification is not requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.430(3), F.A.C.
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			FDEP has not required proof of financial responsibility.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not being requested..
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Permit Review	62-4.150, F.A.C.		X		Failure to request a hearing within 14 days of proposed or final Agency action on a permit application shall be deemed a waiver to the right to an administrative hearing.
Permit Conditions	62-4.160(2), (8), and (14), F.A.C.		X		Lists general conditions that must be contained in permits. Specifically, 62-4.160(2) states that deviations from original specifications or conditions of the permit are not allowed. Under 62-4.160(8) applicants must report the cause and duration of non-conpliance, and 62-4.160(14) requires permit and monitoring records must be maintained at the facility and supplied to FDEP upon request.
Chapter 62-4, F.A.C. - Part II Specific Permits; Requirements					
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits.

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - Air Pollution Control - General Provisions					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.	X			Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W. Air quality modeling is not required for Title V permit applications.
Federal Regulations Adopted by Reference	62-204.800(8), F.A.C.			CC-1	All Federal Regulations cited in the rules by the Department are adopted and incorporated by reference. Specifically, the new source performance standard contained in 40 CFR 60 Subpart GG for Stationary Gas Turbines applies to CC-1.
Federal Regulations Adopted by Reference	62-204.800(10) and (11), F.A.C.		X		National Emissions Standards for Hazardous Air Pollutants; see Table A-1 for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800(16), (17), (18), (20), and (21), F.A.C.			CC-1	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800(23), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Permits Required	62-210.300, F.A.C., except 62-210.300(1) and (4), F.A.C.		X		Air operation permit required, with the exception of certain facilities and sources. Startup notification required if a permitted source has been shut down for more than 1 year.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement).**
Public Notice and Comment	62-210.350(1), F.A.C.		X		All permit applicants, including those for renewals and revisions, are required to publish notice of proposed agency action **(future requirement**).
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.	X			PSD and nonattainment area NSR application not required for permit renewal application.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permits, renewals, and revisions (**future requirement**).

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Administrative Permit Corrections	62-210.360, F.A.C.	X			Application is for Title V operating permit renewal. An administrative permit correction is not requested in this application.
Reports	62-210.370, F.A.C.		X		Title V sources are required to submit an annual operating report.
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Facility does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(2), F.A.C.		X		Specifies annual reporting requirements
Stack Height Policy	62-210.550, F.A.C.	X		CC-1	Limits credit in air dispersion studies to good engineering practice (GEP) stack heights. Except for CC-1, stacks at the J.R. Kelly Station were in existence prior to 12/30/70.
Circumvention	62-210.650, F.A.C.			CC-1	An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700, F.A.C.			Unit No. 7 CC-1	Excess emissions due to startup, shut down, and malfunction are permitted. Excess emissions due to malfunction must be reported. Excess emissions during soot blowing and load change are permitted with restrictions. **(potential *future requirement*)**
Forms and Instructions	62-210.900, F.A.C.		X		List required FDEP forms for stationary sources.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.	X			Air construction permit requirements, not applicable to Title V operating permit renewal applications.
Prevention of Significant Deterioration	62-212.400(7)(b), F.A.C.	X			The operation permit shall contain all operating conditions and provisions required under 62-212.400 and set forth in the original or amended construction permit.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Facility not located in any nonattainment area or nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Responsible Official	62-213.202, F.A.C.		X		Title V sources must designate a responsible official.
Annual Emissions Fee	62-213.205, F.A.C.		X		Title V sources must pay an annual emissions fee.
Title V Air General Permits	62-213.300, F.A.C.	X			Not an eligible facility.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. Lists changes for which a permit revision is required **(potential future requirement).**
Concurrent Processing of Permit Applications	62-213.405, F.A.C.	X			No construction permit is being sought at this time.
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement).**
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CC-1	Optional provisions for Acid Rain permit revisions **(potential future requirement).**
Trading of Emissions within a Source	62-213.415, F.A.C.		X		Defines the conditions under which emissions trading is allowable.
Permit Applications	62-213.420(1)(b)1., and 420(3), F.A.C.		X		Title V operating permit renewal application must contain all the information specified by 62-213.420(3), F.A.C. and be certified by the responsible official.
Permit Issuance, Renewal, and Revision	62-213.430(3), F.A.C.		X		Permits being renewed are subject to the same requirements that apply to permit issuance. Permit renewals shall contain the information specified in 62-210.900(1) and 62-213.420(3), F.A.C.
Permit Content	62-213.440(1), and (2), F.A.C.	X			Agency standard permit requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions.
Forms and Instructions	62-213.900(1), (7), and (8), F.A.C.		X		Lists applicable forms such as "Major Air Pollution Source Annual Emissions Fee," Statement of Compliance," and "Responsible Official Notification."
Chapter 62-214 F.A.C. - Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	62-214.300, F.A.C.		X	CC-1	Facility includes Acid Rain units, therefore facility compliance with 62-213 and 62-214, F.A.C., is required.
Applications	62-214.320, F.A.C.		X	CC-1	Requires Title V sources having Acid Rain unit(s) to submit an Acid Rain Application to FDEP.
Acid Rain Compliance Plan and Compliance Options	62-214.330, F.A.C.			CC-1	Acid rain compliance plan must be submitted to the Department.
Exemptions	62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement).**
Certification	62-214.350, F.A.C.		X	CC-1	The designated representative must certify all Acid Rain submissions.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Department Action on Applications	62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	62-214.370, F.A.C.		X		Defines revision procedures and automatic amendments **(potential future requirement)**.
Acid Rain Part Content	62-214.420, F.A.C.	X			Agency requirements - defines content of Acid Rain Part.
Implementation and Termination of Compliance Options	62-214.430, F.A.C.		X		Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-252 - Gasoline Vapor Control					
Rules for gasoline vapor control equipment	62-252, F.A.C.	X			Facility not located in an ozone nonattainment area or an air quality maintenance area for ozone
Chapter 62-256, F.A.C. - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	62-256.300, F.A.C.*		X		Prohibits open burning.
Agricultural and Silvacultural Fires	62-256.400, F.A.C.	X			Contains no applicable requirements.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Land Clearing	62-256.500, F.A.C.*		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	62-256.600, F.A.C.*		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.	X			Contains no applicable requirements.
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Program					
Controls release of asbestos to the atmosphere and establishes fees.	62-257.301, .400, and .900, F.A.C.*		X		Requires notice and payment of fee for asbestos removal projects **(potential future requirement).**
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling					
Establishes installation and proper use of motor vehicle refrigerant recycling equipment.	62-281.100, F.A.C.		X		Servicing of motor vehicle air conditioners and vehicle maintenance that may release refrigerants is conducted.
Chapter 62-296 - Stationary Sources - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department. No such devices have been required at J.R. Kelly Station.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.*		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	62-296.320(3), F.A.C.*		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited. **(potential future requirement)**
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Facility does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Existing Fossil Fuel Fired Steam Generators with More Than 250 MMBtu/hr Heat Input	62-296.405(1)(a), (b), (c)1.j. and (c)3., (e)1, 2, 3, and 5, and (f)1.a. and b., and g., F.A.C.			Unit No. 7	(1)(a) Visible Emissions - 20 percent opacity except for one two minute period per hour during which opacity shall not exceed 40 percent.
					(1)(b) Particulate matter emissions shall not exceed 0.1 pounds per million Btu heat input.

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
					(c)1.j. When combusting liquid fuels sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input.
					(1)(e)1. Test method for visible emissions may be by DEP Method 9, or transmissometer.
					(1)(e)2. Specifies test methods for particulate matter.
					(1)(e)3. Allows fuel sampling as an alternate test method for sulfur dioxide compliance. Sulfur content of liquid fuels shall not exceed 2.50% by weight per Title V permit.
					(f)1.a. Exempts opacity monitoring for oil and gas units.
					(f)1.b. Allows fuel sampling for sources not having a flue gas desulfurization process.
					(f)1.g. Requires quarterly reporting of excess emissions.
New and Existing Fossil Fuel Fired Steam Generators with Less Than 250 MMBtu/hr Heat Input	62-296.406(1), (2), (3), F.A.C.	X			No applicable unit at facility.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.404 and 62-296.407 through 62-296.417, F.A.C.	X			No applicable unit at facility.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 13 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Facility is not located in an ozone nonattainment area or an ozone air quality maintenance area.
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Facility is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (Broward, Dade and Palm Beach Counties).
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Facility not located in a lead nonattainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	62-296.700 through 62-296.712, F.A.C.	X			Facility not located in a PM nonattainment area or a PM air quality maintenance area.
Chapter 62-297, Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Test Requirements	62-297.310, F.A.C.			Unit No. 7, CC-1	Specifies general compliance test requirements including the number of runs, operating rates, emission rate calculation, applicable test procedures, determination of process variables, required stack sampling facilities, frequency of tests, and content of test reports.
Compliance Test Methods	62-297.401, F.A.C.		X		List methods to be used for compliance testing.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains other test procedures adopted by reference.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 14 of 14)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Contains no applicable requirements.
CEMS Performance Specifications	62-297.520, F.A.C.			CC-1	Contains performance specifications for continuous emissions monitoring.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

*State requirement only; not federally enforceable.

Source: ECT, 2003.

APPENDIX B

PROPOSED TITLE V PERMIT

A mark-up of the current Title V Air Operation Permit for the J.R. Kelly Generating Station is provided for Department consideration. This mark-up includes the specific permit condition revisions requested by GRU. However, GRU reserves the right to provide the Department with additional permit condition suggestions in the future as well as to comment on the Department's draft Title V permit renewal for the J.R. Kelly Generating Station.

Draft (June 2003)

City of Gainesville, GRU
J. R. Kelly Generating Station
Facility ID No.: 0010005
Alachua County

Title V Air Operation Permit Revision
FINAL Permit Revision No.: 0010005-003-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority:
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7590
Telephone: 904/807-3300~~448-4300~~
Fax: 904/448-4363

~~and~~

~~Department of Environmental Protection~~
~~Northeast District Branch Office~~
~~101 NW 75 Street, Suite 3~~
~~Gainesville, Florida 32607-1609~~
~~Telephone: 352/333-2850~~
~~Fax: 352/333-2856~~

Note: This office no longer has staff for air-related issues. The DEP NE District Office has instructed GRU to direct all compliance related notifications and reports required by this permit to the District Office only until instructed otherwise.

Title V Air Operation Permit Revision
FINAL Permit Revision No.: 0010005-003-AV

Table of Contents

Section **Page Number**

Rationale: Unit No. 6 has been permanently retired. Suggest consolidating all permit conditions for Unit No. 7 in one section.

Permittee:
City of Gainesville, GRU
P.O. Box 147117 (A134)
Gainesville, FL 32614-7117

FINAL Permit Revision No.: 0010005-003-AV
Facility ID No.: 0010005
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Revision

This permit is for the operation of the J. R. Kelly Generating Station. This facility is located at 605 SE 3rd Street, Gainesville, Alachua County; UTM Coordinates: Zone 17, 372.00 km East and 3280.20 km North; Latitude: 29° 38' 48" North and Longitude: 82° 19' 19" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix GG, NSPS Subpart GG Requirements for Gas Turbines
APPENDIX TV-4~~3~~, TITLE V CONDITIONS (version dated 02/12/02~~04/30/99~~)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96)
Acid Rain Phase II Permit Application received January 2, 1996.
Alternate Sampling Procedure: ASP Number 97-B-01 (including the Order Correcting the Scrivener's Error dated July 2, 1997).
Acid Rain Phase II Permit Application Revision received January 29, 1999.
Federal Acid Rain Retired Unit Exemption Application received October 9, 2000.
State Acid Rain Retired Unit Exemption Application received October 25, 2000.
Construction Permit 0010005-002-AC issued February 24, 2000.

Effective Date: January 1, 2004~~1999~~
Revision Effective Date: December 5, 2000
Renewal Application Due Date: July 5, 2008~~3~~
Expiration Date: December 31, 2008~~3~~

Howard L. Rhodes, Director
Division of Air Resources
Management

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of one~~two~~ fossil fuel fired steam generators~~s~~, and a combined-cycle unit consisting of a combustion turbine and a heat recovery steam generator. The facility is fired with either natural gas, distillate fuel oils (Nos. 1 or 2), or ~~new~~ residual fuel oils (Nos. 4, 5, or 6) which may be supplemented with on-specification used oil. ~~Unit 6 is permitted to burn natural gas only.~~

Also, included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the ~~initial~~ Title V permit renewal application received ~~June 14~~ (Insert) ___, 2003~~1996~~, this facility is not a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions.

E.U. ID No.	Brief Description
~~-006~~	~~Fossil Fuel Fired Steam Generator Unit No. 6~~
-007	Fossil Fuel Fired Steam Generator Unit No. 7
-010	Combined-Cycle Unit No. 1 (CC-1), consisting of a combustion turbine and a heat recovery steam generator

-009 Unregulated Emissions Units and/or Activities (see Appendix U-1)

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes

These documents are on file with the permitting authority:
Initial Title V Permit Application received June 14, 1996.
U.S. EPA Region 4 Objection Letter to DEP received May 4, 1998.
DEP response to U.S. EPA Region 4 Objection Letter dated July 27, 1998.
U.S. EPA Region 4 Resolution Letter to DEP received August 14, 1998.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4~~3~~, TITLE V CONDITIONS (version dated 04/30/99), is a part of this permit.
{Permitting note: APPENDIX TV-4~~3~~, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4, F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable ; and
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6), and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
[Rule 62-296.320(1)(a), F.A.C.]

{Permitting note: The Department has not ordered any control devices or systems under Rule 62-296.320(1)(a), F.A.C.}

8. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

9. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Northeast District Office~~ and the Department's Gainesville Branch Office~~:

Department of Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, FL 32256-7590
Telephone: 904/807-3300~~448-4300~~
Fax: 904/448-4363

~~and~~

~~Department of Environmental Protection~~
~~Northeast District Branch Office~~
~~101 NW 75 Street, Suite 3~~
~~Gainesville, FL 32607-1609~~
~~Telephone: 352/333-2850~~
~~Fax: 352/333-2856~~

Rationale: The Department's Northeast District Office has indicated that there are no air personnel at the Gainesville Branch Office and that it is unlikely that the position will be filled in the future. They have instructed us to direct all compliance related notifications and reports required by this permit to the District Office only until instructed otherwise.

10. Except as otherwise provided herein, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

11. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch, Air Compliance Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9099
Fax: 404/562-9095

{Permitting note: Condition no. 51 of Appendix TV-4~~3~~, lists the necessary elements of a compliance certification required under 40 C.F.R. 70.6(c)(5)(iii).}

12. For all emission limits where averaging times are not otherwise specified, the averaging times for specified emission standards are tied to or based on the run time of the test method(s) used for determining compliance.

Section III. Emissions Units and Conditions.

Delete the following Subsection A in its entirety. This unit has been permanently retired.

~~**Subsection A. This section addresses the following emissions unit.**~~

~~**E.U. ID No.**~~	~~**Brief Description**~~
~~-006~~	~~Fossil Fuel Fired Steam Generator Unit No. 6~~

~~Fossil Fuel Fired Steam Generator Unit 6 is a nominal 19 megawatt (electric) steam generator with no emissions control equipment. The emissions unit is fired on natural gas with a maximum heat input of 187.3 MMBtu per hour. Fossil Fuel Fired Steam Generator Unit No. 6 began commercial operation in March 1958 and has been on cold standby since August 1, 1989.~~

~~{Permitting note: The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input.}~~

~~**The following specific conditions apply to the emissions unit listed above:**~~

~~**Essential Potential to Emit (PTE) Parameters**~~

~~**A.1.** Permitted Capacity. The maximum operation heat input rate, based on the higher heating value (HHV) of the fuel, is as follows:~~

~~Unit No.~~	~~MMBtu/hr Heat Input (HHV)~~	~~Fuel Type~~
~~6~~	~~187.3~~	~~Natural Gas~~

~~[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]~~

~~{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limitations and to aid in determining future rule applicability.}~~

~~**A.2.** Emissions Unit Operating Rate Limitation After Testing. See **Specific Condition C.9.** [Rule 62-297.310(2), F.A.C.]~~

~~**A.3.** Methods of Operation. Fuels.~~
~~The only fuel allowed to be burned during startup and normal operations is natural gas. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]~~

~~Emission Limitations and Standards~~

~~{Permitting note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}~~

~~**A.4.** Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.~~
~~[Rule 62-296.406(1), F.A.C.]~~

~~**A.5.** Visible emissions - Soot Blowing and Load Change. Excess emissions from the existing fossil fuel steam generator resulting from boiler cleaning (soot blowing) and load change shall be permitted provided the duration of such excess emissions shall not exceed 3 hours in any 24-hour period and visible emissions shall not exceed 60 percent opacity, and providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized.~~

~~A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.~~
~~[Rule 62-210.700(3), F.A.C.]~~

~~**A.6.** Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas.~~
~~[Rule 62-296.406(2), F.A.C.; BACT dated October 9, 1991 and proposed by applicant on October 31, 1997]~~

~~**A.7.** Sulfur Dioxide. Sulfur dioxide emissions shall be controlled by the firing of natural gas.~~
~~[Rule 62-296.406(3), F.A.C.; BACT dated October 9, 1991 and proposed by applicant on October 31, 1997]~~

~~Test Methods and Procedures~~

~~{Permitting note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}~~

~~**A.8.** Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. See **Specific Conditions C.8. and A.10.**~~
~~[Rules 62-213.440 and 62-297.401, F.A.C.]~~

~~A.9.~~ ~~Applicable Test Procedures.~~
~~(a) Required Sampling Time.~~
~~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. 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:~~
~~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.~~
~~[Rule 62-297.310(4)(a)2., F.A.C.]~~

~~A.10.~~ ~~By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning only gaseous fuels.~~
~~[Rule 62-297.310(7)(a)4., F.A.C.]~~

~~Recordkeeping and Reporting Requirements~~

~~A.11.~~ ~~All recorded data shall be maintained on file by the source for a period of five years.~~
~~[Rule 62-213.440(1)(b)2.b., F.A.C.]~~

~~Miscellaneous Condition~~

~~A.12.~~ ~~This emissions unit is also subject to conditions contained in~~ **~~Subsection C.~~**

Since Unit 6 has been retired, this subsection should now be new Subsection A. The conditions from Subsections C and D should be incorporated into this section. Conditions in this section which cross-reference conditions in Subsections C and D should be revised accordingly after the sections are consolidated.

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-007	Fossil Fuel Fired Steam Generator Unit No. 7

Fossil Fuel Fired Steam Generator Unit No. 7 is a nominal 25 megawatt (electric) steam generator with no emissions control equipment. The emissions unit is fired on natural gas and/or ~~new~~ residual fuel oils (Nos. 4, 5, or 6). The maximum heat input for natural gas and ~~new~~ residual fuel oils (Nos. 4, 5, or 6) are 272 MMBtu per hour and 249 MMBtu per hour, respectively.

The ~~new~~ residual fuel oils (Nos. 4, 5, or 6) fired in Fossil Fuel Fired Steam Generator Unit No. 7 may be supplemented with a limited amount of on-specification used oil.

{Permitting notes: The emissions units are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil Fuel Fired Steam Generator Unit No. 7 began commercial operation in August 1961. ~~The term "new" is hereby defined as "nonused".~~}

Rationale: Use of the adjective "new" with respect to residual fuel oils is not necessary since used oil is addressed in Subsection D.

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rates, based on the higher heating value (HHV) of the fuel, are as follows:

Unit No.	MMBtu/hr Heat Input (HHV)	Fuel Type
7	272	Natural Gas
	249	~~New~~ Rresidual fuel oils (Nos. 4, 5, or 6); On-Specification Used Oil

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limitations and to aid in determining future rule applicability.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See **Specific Condition C.9.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Fuels.

a. Startup: The only fuels allowed to be burned are natural gas and/or ~~new~~ Nos. 4, 5 or 6 fuel oil, which may be supplemented with on-specification used oil with a PCB concentration less than 2 ppm.

b. Normal: The only fuels allowed to be burned are natural gas and/or ~~new~~ No. 4, 5 or 6 fuel oil, which may be supplemented with on-specification used oil with a PCB concentration less than 50 ppm.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.4. Visible Emissions. Visible emissions from this ~~each~~ unit shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Except as otherwise specified in **Specific Condition B.21.**, emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. See Conditions B.20, C.6 and C.10 for visible emission testing requirements.
[Rule 62-296.405(1)(a), F.A.C.]

Rationale: Language is suggested for clarification of the testing requirements.

B.5. Visible Emissions - Soot Blowing and Load Change. Excess emissions from the existing fossil fuel steam generator resulting from boiler cleaning (soot blowing) and load change shall be permitted provided the duration of such excess emissions shall not exceed 3 hours in any 24-hour period and visible emissions shall not exceed 60 percent opacity, and providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

B.6. Particulate Matter. Particulate matter emissions from each unit shall not exceed 0.1 pound per million Btu heat input , as measured by applicable compliance methods. See **Specific Condition B.12.** for the applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.7. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3 hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. See Condition C.10(a)2 for testing requirements related to this conditions.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

Rationale: Language is added for clarification of testing requirements.

B.8. Sulfur Dioxide. While combusting liquid fuels, sulfur dioxide emissions from this~~each~~ unit shall not exceed 2.75 pounds per MMBtu heat input, as measured by applicable compliance methods. See **Specific Conditions B.13. and B.14.** for the applicable compliance methods.
[Rule 62-296.405(1)(c)j., F.A.C.]

B.9. Sulfur Dioxide. The sulfur content of liquid fuels shall not exceed 2.50% sulfur, by weight. See **Specific Condition B.15.**
[Rule 62-296.405(1)(e)3., F.A.C., and requested by applicant in a letter dated October 30,1997]

Test Methods and Procedures

{Permitting note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.10. [Reserved.]

B.11. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.
[Rule 62-296.405(1)(e)1., F.A.C.]

B.12. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. EPA Method 3 (with Orsat analysis) or 3A shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

B.13. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee may elect to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each delivery.**
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.]

B.14. Sulfur Dioxide. **The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device.
[Rule 62-296.405(1)(f)1.b., F.A.C.]

B.15. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, ASTM D1552-90, ASTM D2622-98, ~~ASTM D4177-82 or both ASTM D4057-88~~ and ASTM D129-91 or the latest edition of the above ASTM methods.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

Rationale: The listing has been updated to reflect an additional method in Rule 62-297.440(1).

B.16. 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 the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

B.17. 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 separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

B.18. 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 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. 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:

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, attached to this permit.
(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.
[Rule 62-297.310(4), F.A.C.]

B.19. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

B.20. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

a. only gaseous fuels; or
b. only liquid fuels, other than during startup, for no more than 400 hours per federal fiscal year; or
c. gaseous fuels in combination with liquid fuels, other than during startup, for no more than 400 hours per federal fiscal year.

[Rule 62-297.310(7)(a)4., F.A.C.]

B.21. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:

a. only gaseous fuels; or
b. only liquid fuels, other than during startup, for no more than 400 hours per federal fiscal year; or
c. gaseous fuels in combination with liquid fuels, other than during startup, for no more than 400 hours per federal fiscal year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Recordkeeping and Reporting Requirements

B.22. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440 and 62-296.405(1)(g), F.A.C.]

~~**Miscellaneous Conditions**~~

~~**B.23.** This emissions unit is also subject to conditions contained in **Subsections C. and D., Common Conditions.**~~

Rationale: Since there is now only one fossil fuel fired steam generator, suggest consolidating all permit conditions applicable to Unit No. 7 in Section A.

Subsection C. Common Conditions.

E.U. ID No.	Brief Description
~~-006~~	~~Fossil Fuel Fired Steam Generator Unit No. 6~~
-007	Fossil Fuel Fired Steam Generator Unit No. 7

Since there is now only one fossil fuel fired steam generator, suggest consolidating all Subsection C. permit conditions applicable to Unit No. 7 in Subsection A.

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Excess Emissions

C.2. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.3. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

C.4. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

C.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.
[Rule 62-297.310(5), F.A.C.]

C.6. Additional Testing for Periodic Monitoring~~ for Unit 7~~. In addition to the visible emission test required per **Specific Condition C.10.**, upon exceeding 400 hours of operation on fuel oil, the owner or operator shall conduct an additional test for visible emissions using DEP Method 9 every 150 hours of operation on fuel oil thereafter, for the purposes of periodic monitoring. Furthermore, the owner or operator shall conduct a visible emissions test on fuel oil prior to renewal of the permit.
[Rule 62-213.440, F.A.C. and applicant's agreement on June 26 and July 27, 1998]

C.7. [Reserved.]

~~{Permitting note: Unit No. 6 is permitted to burn natural gas only. The Department has concluded that the recordkeeping and reporting requirements specified in this permit are appropriate and adequate for purposes of periodic monitoring.}~~

Test Methods and Procedures
{Permitting note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.8. 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.
[Rule 62-297.401, F.A.C.]

C.9. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable 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 emissions 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.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

C.10. 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. (not applicable)

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 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 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; See Condition B.20.

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 fuel, other than during startup, for a total of no more than 400 hours and as otherwise specified in **Specific Condition B.21.**

~~6.-8. (not applicable)~~

~~9. See **Specific Condition C.12.**~~

Rationale: Above conditions do not appear necessary.

(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 may 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.
[Rule 62-297.310(7), F.A.C.; SIP approved]

Recordkeeping and Reporting Requirements

C.11. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Northeast District Office ~~and the Northeast District Branch Office~~ in accordance with Rule 62-4.130, F.A.C. (Appendix TV-4~~3~~, Title V Condition No. 9). A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

C.12. The owner or operator shall notify the Northeast District Office of the Department ~~and the Northeast District Branch Office~~, 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.
[Rule 62-297.310(7)(a)9., F.A.C.]

C.13. 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's Northeast District Office ~~and the Northeast District Branch Office~~ on the results of each such test.
(b) The required test report shall be filed with the Department's Northeast District Office ~~and the Northeast District Branch Office~~ 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, if required by the test method:

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.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

C.14. Recordkeeping for periodic monitoring. The owner or operator is required to record the date, time and duration of each soot blowing and load change event.
[Rule 62-213.440, F.A.C.]

Subsection D. Common Conditions.

E.U. ID No.	Brief Description
-007	Fossil Fuel Fired Steam Generator Unit No. 7

Since there is now only one fossil fuel fired steam generator, suggest consolidating all Subsection D. permit conditions applicable to Unit No. 7 in Subsection A.

The following specific conditions apply to the emissions unit listed above:

D.1. Used Oil. Burning of on-specification used oil is allowed at this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: These emissions units are permitted to burn "on-specification" used oil, not to exceed 1.5 million gallons during any consecutive 12 month period.

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration equal to or greater than 2 ppm and less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration equal to or greater than 2 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

(1) Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

(2) Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

(3) Alternatively, the owner or operator may rely on other analyses or other information to make the determination that the used oil meets the specifications of 40 CFR 279.11. Documentation used to make the determination shall be maintained at the facility.

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.72, 40 CFR 279.74(b) and 761.20(e)]

(1) The gallons of on-specification used oil placed in inventory each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)

(2) The total gallons of on-specification used oil placed in inventory in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)

(3) Results of the analyses required above.

g. Reporting Requirements: ~~The owner or operator shall submit to the Northeast District office and the Northeast District Branch Office, within thirty days of the end of each calendar quarter, the analytical results and the total amount of on-specification used oil placed in inventory during the quarter.~~

The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil placed in inventory during the previous calendar year. This reporting requirement does **not** apply if there was no used oil placed in inventory during the previous calendar year.

[Rule 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

Rationale: The deletion is to lessen the reporting burden. The additional language is to clarify the reporting requirements.

Subsection E. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-010	Combined-Cycle Unit No. 1 (CC-1), consisting of a combustion turbine and a heat recovery steam generator

The unit consists of a nominal 83 megawatt (MW) natural gas and/or No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a 102 foot stack for combined cycle operation; a 88 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. The combustion turbine may be equipped with inlet air conditioning devices (e.g., evaporative chillers, foggers, etc.). NO_x emissions will be controlled through the use of low-NO_x burners during natural gas firing and water injection when firing fuel oil.

~~This new unit is permitted under Permit No. PSD-FL-276, 0010005-002-AC, issued February 24, 2000.~~ As required under the federal Acid Rain Program, the unit is~~will be~~ equipped with a CEMS to measure SO_2, NO_x, and CO_2.

The following specific conditions apply to the emission unit listed above:

E.1.1. NSPS Requirements – Subpart GG: Except as otherwise specified in this permit, ~~T~~the combustion turbine ~~Unit~~ shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(8~~7~~)(b), F.A.C. The Department determines that compliance with the emission limitations of Conditions E.12 and E.15. and the monitoring requirements of Conditions E.22, E.24, E.37, E.39, and E.40 also demonstrates compliance with the New Source Performance Standards for gas turbines in 40 CFR 60, Subpart GG. For completeness, the applicable Subpart GG requirements are included in Appendix GG of this permit. ~~The Subpart GG requirement to correct test data to ISO conditions applies when determining compliance with the emissions limitations specified therein.~~

[Rule 62-4.070(3), F.A.C.].
[0010005-002-AC]

Rationale: Clarify that the more stringent BACT emission limits also satisfy NSPS Subpart GG; provide summary of applicable NSPS Subpart GG requirements in an appendix consistent with current Department permitting procedures, and clarify that certain requirements have been specified as alternatives to Subpart GG requirements.

E.1.2. NSPS Requirements – Subpart A: The~~se~~ combustion turbine ~~emission units~~ shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

40CFR60.7, Notification and Recordkeeping
40CFR60.8, Performance Tests
40CFR60.11, Compliance with Standards and Maintenance Requirements
40CFR60.12, Circumvention
40CFR60.13, Monitoring Requirements
40CFR60.19, General Notification and Reporting requirements

[0010005-002-AC]

~~E.1.3. Operation of the emissions unit beyond the time frames established by the AC permit is allowed, provided the Department has received and verified a properly signed and sealed certification from the permittee's Professional Engineer stating that 1) the construction of the emissions unit was completed in accordance with the AC permit and 2) the emissions unit has been tested and compliance with the terms and conditions contained within the AC permit has properly been demonstrated.~~
~~[Rules 62-212.400(7)(b), 62-213.440(2), and 62-213.420(1)(a)5., F.A.C.]~~

Rationale: Obsolete condition.

General Operation Requirements

E.2. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur No. 2 or superior grade of distillate fuel oil shall be fired in this unit.

[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); 0010005-002-AC]

E.3. Combustion Turbine Capacity: The maximum heat input rates, based on the higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); 0010005-002-AC]

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

E.4. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

[Rule 62-296.320(4)(c), F.A.C.; 0010005-002-AC]

E.5. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Northeast District Office ~~and Northeast District Branch Office~~ as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.

[Rule 62-4.130, F.A.C.; 0010005-002-AC]

E.6. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions.

[Rule 62-4.070(3), F.A.C.; 0010005-002-AC]

E.7. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year (or no more than 1,008,500 mmBtu per year) may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the annual nitrogen oxides (NO_x) emission cap described in Specific Condition **E.12.** below.

[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); 0010005-002-AC]

Rationale: The 1,000 hours of operation per year on fuel oil translates into an equivalent fuel oil consumption of 1,008,500 mmBtu per year based on baseload conditions at 59°F – see Attachment D, page 12 of the J.R. Kelly Generating Station Repowering Project Application for Air Construction Permit and Title V Air Operation Permit Revision.

Control Technology

E.8. DLN Combustion Technology: The permittee shall ~~install,~~ tune, operate and maintain Dry Low NO_x combustors on this combustion turbine. ~~The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation.~~

[Rule 62-4.070, F.A.C.; 0010005-002-AC]

Rationale: Obsolete condition language.

E.9. Water Injection: The permittee shall ~~install,~~ calibrate, maintain and operate an automated water injection system for the unit for use when firing fuel oil. ~~The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation.~~

[Rule 62-4.070, F.A.C.; 0010005-002-AC]

Rationale: Obsolete condition language.

E.10. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, and NO_x, and VOC emissions. ~~Prior to the required initial emissions performance testing, T~~Tthe combustion turbine, the DLN-1 combustors, and the control system ~~shall be tuned to comply with the CO, and NO_x, and VOC emission limits. Thereafter, these systems~~ shall be maintained and tuned, as necessary, in accordance with manufacturer's recommendations for emissions control and to comply with the permitted emission limits.

[Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.; 0010005-002-AC].

Rationale: Obsolete condition language.

E.11. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.

[Rule 62-210.650, F.A.C.; 0010005-002-AC]

Emission Limitations and Standards

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

E.12. Nitrogen Oxides (NO_x) Emissions:

- Natural Gas Operation. The concentration of NO_x in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 720 operating hour block average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). ~~Emissions of NO_x in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test.~~ [Rule 62-4.070(3), F.A.C.; 0010005-002-AC]
- Fuel Oil Operation. The concentration of NO_x in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 720 operating hour block average. Compliance will be demonstrated

by the CEMS. ~~Emissions of NO_x shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test.~~

[Rule 62-4.070(3), F.A.C.; 0010005-002-AC]

Rationale: Obsolete conditions. FDEP determined that correction of lb/hr to ISO conditions was not necessary. See E-mail from Y. Jonynas to J. Kahn, FDEP, dated 7/13/01.

- Annual Emission Cap: Total emissions of NO_x from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Compliance will be demonstrated by the CEMS, as specified in Specific Condition **E.23.**

[Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070 (3), F.A.C.; 0010005-002-AC]

E.13. Carbon Monoxide (CO) Emissions:

~~Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd. Emissions of CO shall not exceed 54 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.; 0010005-002-AC]~~

- Natural Gas ~~(Second Year and Beyond)~~ or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed 43 lb/hr ~~(at ISO conditions)~~. Compliance shall be demonstrated by a stack test using EPA Method 10 or as otherwise specified in Condition E.25. [Rule 62-212.400, F.A.C.; 0010005-002-AC]

Rationale: Obsolete condition language. FDEP determined that correction of lb/hr to ISO conditions was not necessary. See E-mail from Y. Jonynas to J. Kahn, FDEP, dated 7/13/01. Clarify that there is an alternative to stack testing.

E.14. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. ~~Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A.~~ Compliance shall be demonstrated as specified in Condition E.26.

[Rule 62-4.070(3), F.A.C.; 0010005-002-AC]

Rationale: Obsolete condition. FDEP determined that correction of lb/hr to ISO conditions was not necessary. See E-mail from Y. Jonynas to J. Kahn, FDEP, dated 7/13/01.

E.15. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for up to 1000 hours per year (or no more than 1,008,500 mmBtu per year). Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions **E.39.** and **E.40.** will demonstrate compliance with the applicable SO_2 NSPS.

[40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.; 0010005-002-AC]

E.16. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing.

[Rules 62-212.400, and 62-4.070(3) F.A.C.; 0010005-002-AC].

E.17. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.; 0010005-002-AC]

Excess Emissions

E.18. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching or malfunction shall be permitted provided that best operational practices are adhered

to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except as follows:

- During "cold start-up" to combined cycle plant operation up to four hours of excess emissions are allowed. A cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours.
- During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed.
- Unless authorized by the Department.

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

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

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

[Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.; 0010005-002-AC].

Rationale: Excess NO_x emissions are already defined in Condition E.36. The definition of "cold start-up" has been moved for clarification. The word "cap" has been deleted.

E.19. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These excess emissions shall be included in the 720 operating hour block average for NO_x.

[0010005-002-AC]

Compliance Determination and Testing Requirements

E.20. Compliance Time: Except as otherwise specified in this permit, ~~C~~compliance with the allowable emission limiting standards shall be determined ~~within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and~~ annually ~~thereafter~~ as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (~~1999~~ most current version), and adopted by reference in Chapter 62-204.800, F.A.C.

[0010005-002-AC]

Rationale: Obsolete condition language. Language added to recognize that Appendix A may be periodically revised and to recognize that exceptions to annual testing and compliance methods are provided in the permit.

E.21. ~~Annual, Initial and Performance~~ Testing: ~~Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition E.20. Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change of combustors. Year two (YR2) compliance testing for CO shall be performed in the second year of operation.~~ Except as otherwise specified in this permit, ~~A~~annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this unit as indicated. Compliance tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) that may effect emissions such as change of combustors. The following reference methods shall be used.

No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (~~I,~~ A). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (~~I and~~ A ~~(YR2 and beyond~~, gas only).

- ~~EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG. Test data shall be corrected to ISO conditions.~~

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

[0010005-002-AC]

Rationale: Obsolete condition language. Exceptions to annual testing are provided in the permit.

E.22. Continuous Compliance with the time-averaged NO_x Emission Limits:

- Continuous compliance with the time-averaged NO_x emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 720 operating hour block average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 720 operating hour block and a new average NOx concentration ~~emission rate~~ is calculated from the arithmetic average of all valid hourly NOx concentrations~~emission rates~~ from the next 720 operating hour block average. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

- A valid hourly NOx concentration~~emission rate~~ shall be calculated for each hour in which at least two NO_x concentrations are obtained at least 15 minutes apart. Valid hourly NOx concentrations~~emission rates~~ shall not include periods of start up, shutdown, fuel switching, or malfunction unless not authorized by Rule 62-210.700 F.A.C. or Specific Condition **E.18.**

- Periods when the 720 operating hour block average or the ~~133 TPY calendar year~~ annual emissions cap on NO_x exceeds the emission limitations specified in Specific Condition **E.12.**, shall be reported as required by Specific Condition **E.36**.

[0010005-002-AC]

E.23. Compliance with the NO_x Annual Emission Cap:

Total emissions of NO_x from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Annual emissions shall be calculated using the methodology in 40 CFR 75.71 and 40 CFR 75.72 and 40 CFR Part 75, Appendix F, Section 8.4 and shall be reported to the District office on the Annual Operating Report. The owner or operator shall notify the Department as specified in Specific Condition **E.36.** if annual emissions exceed the NO_x cap based on cumulative calculations which are done each month. [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

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

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

- Specific Condition **E.36.** provides a specific timeframe for reporting if the NO_x cap is exceeded.

[0010005-002-AC]

E.24. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas~~;~~ and distillate fuel with a sulfur content no greater than 0.05% weight and visible emission testing ~~is~~ are~~; is~~ the methods for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, the following procedures in 40 CFR 60.335 or 40 CFR 75 shall be used when determination of fuel sulfur content of gaseous fuel is made: ASTM methods D1072-90, D4468-85, D3246-81~~ASTM methods D4084-82~~ or D3246-81 (or equivalent) ~~for sulfur content of gaseous fuel~~ These procedures shall be utilized in accordance with the EPA-approved custom fuel monitoring schedules (See Conditions E.39 and 40). Alternatively, ~~or~~ natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1999 version).

[Applicant request; 0010005-002-AC]

Rationale: The procedures referenced above have been updated to include those found in both 40 CFR 60.335 and 40 CFR 75, Appendix D, 2.3.3.1.2.

E.25. Compliance with CO emission limit: ~~An initial test for CO, shall be conducted concurrently with the initial NO_x test, as required. The initial NO_x and CO test results shall be the average of three valid one-hour runs.~~ Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the RATA testing for the NO_x CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted.

[Rule 62-297.310(7)(a) 4.; Rule 62-212.400 and 62-4.070(3) F.A.C.; 0010005-002-AC]

Rationale: Obsolete condition language.

E.26. Compliance with the VOC emission limit: ~~An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter,~~ T~~t~~he CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.

[Rule 62-4.070(3) F.A.C; 0010005-002-AC]

Rationale: Obsolete condition language.

E.27. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted.

Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

[Rule 62-297.310(2) F.A.C.; 0010005-002-AC]

E.28. Test Notification: The DEP's Northeast District ~~and Northeast District Branch Offices~~ shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

[Rules 62-297.310(7)(a)9 F.A.C and 40 CFR 60.7 and 60.8; 0010005-002-AC]

E.29. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

[Rule 62-297.310 (7)(b) F.A.C.; 0010005-002-AC]

E.30. Test Results: Compliance test results shall be submitted to the DEP's Northeast District ~~and Northeast District Branch Offices~~ no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.; 0010005-002-AC]

Recordkeeping and Reporting Requirements

E.31. Records: All measurements, records, and other data required to be maintained by GRU shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

[Rules 62-4.160(14) and 62-213.440(1)(b)2.,F.A.C.; 0010005-002-AC]

E.31.1. Fuel Oil Use. To ensure compliance with the hourly limitations in Specific Conditions **E.7.** and **E.15.**, the source shall monitor and record operating hours for fuel oil use.

[Rule 62-213.440(1)(b), F.A.C.]

E.32. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

[Rule 62-297.310(8), F.A.C.; 0010005-002-AC]

E.33. Excess Emissions Report: If excess emissions occur ~~(as specified in Specific Condition **E.18.**)~~ for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District ~~and Northeast District Branch~~ Offices within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following the format of 40 CFR 60.7, periods of startup, shutdown, fuel switching and malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Conditions No. ~~**E.12.** and~~ **E.17. and E.36.**
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1999 version); 0010005-002-AC].

Rationale: The permit defines excess emissions as one-hour periods when emissions are above 9/42 ppmvd@ 15% O_2 when firing natural gas/fuel oil (Condition E.36). While Condition E.12 does impose NO_x limitations that are subject to reporting pursuant to Condition E.36, they are not defined as "excess emissions" under NSPS or the permit.

Monitoring Requirements

E.34. Continuous Monitoring System (CEMS): The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen

oxides emissions from these units. Upon request from EPA or DEP, the CEMS concentrations ~~emission rates~~ for NO_x on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332.

[Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1999 version); 0010005-002-AC].

E.35. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average.

[40CFR60.13; 0010005-002-AC]

E.36. CEMS for Reporting Excess Emissions and Emissions Above the 720-Operating Hour Block Average or the Annual Emissions Cap : The NO_x CEMS shall be used to determine periods of excess emissions. For purpose of reporting, one-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas/fuel oil shall be defined and reported as excess emissions in accordance with Specific Condition **E.33.** CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7

(d)(2). For purposes of excess emission reporting, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Periods when time-averaged NO_x emissions [i.e., 720 operating hour block average or the annual total (i.e., 133 TPY calendar year)] are above the emission limitations listed in Specific Condition No. **E.12.**~~15.~~, shall be reported to the DEP Northeast District Office ~~and Northeast District Branch Office~~ within one working day (verbally) followed up by a written explanation postmarked not later than three (3) working days (alternatively by facsimile within one working day).

[Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C. and 40 CFR 60.7 (1999 version); 0010005-002-AC].

Rationale: To clarify what emissions are defined as and need to be reported as excess emissions and what other emissions are subject to reporting.

E.37. CEMS in lieu of Water to Fuel Ratio: The NO_x CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS.

[0010005-002-AC]

E.38. CEMS Certification and Quality Assurance Requirements: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. ~~The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.~~

[0010005-002-AC]

Rationale: Obsolete condition language.

E.39. Custom Fuel Monitoring Schedule (Natural Gas): Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal.

Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meets the definitions of pipeline natural gas or natural gas set forth in ~~(~~40CFR 72~~)~~. A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- ~~The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.~~
- ~~The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of natural gas or pipeline supplied natural gas.~~

- SO_2 emissions shall be monitored using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- This custom fuel monitoring schedule will only be valid when natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

[0010005-002-AC]

Rationale: Obsolete condition language.

E.40. Custom Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content ~~and nitrogen content~~ of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the sulfur analyses was~~ere~~ conducted and shall comply with the requirements of 40 CFR 60.335(d) and 40 CFR 75, Appendix D, 2.2.5 as follows: ASTM D2880-71, D129-91, D1552-90 and D4294-90 or the most current version.~~:~~

[0010005-002-AC, Applicant request]

Rationale:

- Monitoring of the nitrogen content of the fuel oil is required when a source seeks to use a fuel-bound nitrogen credit in determining its NSPS NO_x limit. This unit does not avail itself of such an emission allowance and therefore, the nitrogen sampling serves no purpose. GRU requests that this requirement be deleted.
- This unit utilizes 40 CFR 75 Appendix D procedures to measure SO_2 emissions. Currently, 40 CFR 60.335(d) specifies only ASTM D2880-71 for determining sulfur content in fuel oil. On the other hand, 40 CFR 75 Appendix D, 2.2.5 provides other allowable methods which were recently proposed for incorporation into 40 CFR 60.335(d) and which are included above.

E.41. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, pressure gauges, etc., shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; 0010005-002-AC].

E.42. Alternate Methods of Operation: This unit may operate in simple or combined cycle modes.

[0010005-002-AC]

Section IV. This section is the Acid Rain Part.

Operated by: Gainesville Regional Utilities-J. R. Kelly
ORIS code: 664

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions unit listed below is regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
-010	Combined-Cycle Unit No. 1 (CC-1), consisting of a combustion turbine and a heat recovery steam generator

A.1. The Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of this acid rain unit must comply with the standard requirements and special provisions set forth in the application listed below:

a. DEP Form No. 62-210.900(1)(a), effective 07/01/95; received 01/29/99.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations for the Acid Rain unit is as follows:

E.U. ID No.	EPA ID No.	Year	2000	2001	2002	2003
-010	CC-1	SO2 allowances, under Table 2 of 40 CFR Part 73	0*	0*	0*	0*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the U.S. EPA under Table 2 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1.,2. & 3., F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, Fast-Track Revisions of Acid Rain Parts.
[Rule 62-213.413, F.A.C.]

A.5. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition No.51., Appendix TV-3, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

A.6. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

A.7. Comments, notes, and justifications: none

Subsection B. This subsection addresses Acid Rain, Phase II.

The emissions unit listed below is regulated under Acid Rain Part, Phase II.

E.U. ID No.	Description
-008	Fossil Fuel Fired Steam Generator (boiler) - PERMANENTLY RETIRED

B.1. The "Retired Unit Exemption" form submitted for this facility constitutes the Acid Rain Part application pursuant to 40 CFR 72.8 and is a part of this permit. The owners and operators of this acid rain unit shall comply with the standard requirements and special provisions set forth in DEP Form No. 62-210.900(1)(a)3., dated July 1, 1995, signed by the designated representative on October 24, 2000, and received by the Department on October 25, 2000. This unit is subject to the following: 40 CFR 72.1 which requires the unit to have an Acid Rain Part as part of its Title V permit; 40 CFR 72.2 which provides associated definitions; 40 CFR 72.3 which provides measurements, abbreviations, and acronyms; 40 CFR 72.4 which provides the federal authority of the Administrator; 40 CFR 72.5 which provides the authority of the states; 40 CFR 72.6 which makes the boiler a Phase II unit; 40 CFR 72.10 which gives the public access to information about this unit; and, 40 CFR 72.13 which incorporates certain ASTM methods into 40 CFR Part 72.
[Chapter 62-213, F.A.C. and Rule 62-214.340, F.A.C.]

B.2. Sulfur dioxide (SO_2) allowance allocations for the Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-008	JRK8	**SO_2 allowances, under Table 2 of CFR 73**	58*	58*	58*	58*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the U.S. EPA under Table 2 of 40 CFR 73.

B.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.440(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1., 2., & 3., F.A.C.]

B.4. The designated representative of this acid rain unit applied for an exemption from the requirements of the Federal Acid Rain Program by submitting a completed and signed "Retired Unit Exemption" form (DEP Form No. 62-210.900(1)(a)3., F.A.C., attached) to the Department. The date of permanent retirement is September 2, 2000.
[Rule 62-214.340(2), F.A.C.; and, 40 CFR 72.8.]

B.5. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition No.51., Appendix TV-3, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

B.6. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

B.7. Comments, notes, and justifications: None.

NSPS Subpart GG Requirements for Gas Turbines

The combustion turbine (a component of Emission Unit –010) is subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(8)(b), F.A.C.

NSPS GENERAL PROVISIONS

{Permitting Note: The combustion turbine is subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.}

NSPS Subpart GG Requirements

{Permitting Note: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, Subpart GG adopted by reference in Rule 62-204.800(8)(b), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in ***bold*** *immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.}*

§ 40 CFR 60.332 Standard for Nitrogen Oxides.

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
N≤0.015	0
0.015<N≤0.1	0.04(N)
0.1<N≤0.25	0.004+0.0067(N–0.1)
N>0.25	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

Department requirement: For both natural gas and distillate fuel oil firing, the "F" value shall be assumed to be 0.

{Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The NSPS Subpart GG NOx emission standard (without adjustment for combustion turbine efficiency) is 75 ppmvd corrected to 15% oxygen. GRU is not claiming a FBN credit for distillate fuel oil. The emissions standards in Subsection B, Condition E.12. of this permit are more stringent than this requirement.}

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

§ 40 CFR 60.333 Standard for Sulfur Dioxide.

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 40 CFR 60.334 Monitoring of Operations.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas and distillate fuel oil fired is waived. A NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the permittee shall comply with the custom fuel monitoring schedules of Conditions E.39. and E.40. {Note: This is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.}

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: The continuous compliance demonstration by NOx CEM system data shall substitute for the requirements of paragraph (c)(1). NOx CEM system data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

§ 40 CFR 60.335 Test Methods and Procedures.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$NOx = (NOxo)\ (Pr/Po)^{0.5}\ e^{19(Ho-0.00633)}\ (288°K/Ta)^{1.53}$

where:

NOx	=	emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H_2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The permittee is allowed to conduct future performance tests, if required by the Department or Administrator, at a single load because the permit requires demonstration of continuous compliance with the NOx BACT standards.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The permittee is allowed to make future Subpart GG compliance demonstrations, if required by the Department or Administrator, for NOx emissions using data collected during relative accuracy test audits (RATAs) performed on the NOx monitor. The span value specified in 40 CFR Part 75 shall be used instead of that specified in paragraph (c)(3) above.

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The requirements of 40 CFR 75 Appendix D may be used to determine the fuel sulfur content.

{Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.}

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

{Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.}