TITLE V OPERATION PERMIT
APPLICATION FOR
SHADY HILLS GENERATING STATION
PASCO COUNTY, FLORIDA

Prepared For:
Mirant Corporation
14240 Merchant Energy Way
Shady Hills, Florida 34610

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

March 2002
0139517

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Department of
Environmental Protection

Division of Air Resources Management

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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: **Mirant Corporation**	
2. Site Name: **Shady Hills Generating Station**	
3. Facility Identification Number: **1010373** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **14240 Merchant Energy Way** City: **Shady Hills** County: **Pasco** Zip Code: **34610**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Bruce Lobach, Plant Manager**
2. Application Contact Mailing Address: Organization/Firm: **Shady Hills Generating Station** Street Address: **14240 Merchant Energy Way** City: **Shady Hills** State: **FL** Zip Code: **34610**
3. Application Contact Telephone Numbers: Telephone: **(727) 857 - 1787** Fax: **(727) 857 - 1998**

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.

[X] 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: PSD-FL-280

[ ] 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:________________

Reason for revision:________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **James Packer, Director of Operations, Southeast Business Unit**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Mirant Corporation** Street Address: **1155 Perimeter Center West** City: **Atlanta** State: **GA** Zip Code: **30338-5416**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (**678**) **579** - **7962** Fax: (**678**) **579** - **7358**
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.* James Packer 03-28-02 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: (**352**) **336** - **5600** Fax: (**352**) **336** - **6603**

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 [**X**]*, if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.*

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

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

Signature | Date 3/29/02

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	GE Frame 7FA Combustion Turbine		
002	GE Frame 7FA Combustion Turbine		
003	GE Frame 7FA Combustion Turbine		
004	Fuel Storage Tank (Unregulated)		

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations:
2. Projected or Actual Date of Commencement of Construction:
3. Projected Date of Completion of Construction:

Application Comment

Initial Title V Air Operation Permit Application. The facility has the ability to fire distillate oil and natural gas. This permit addresses the operation of three permitted, simple-cycle CTs (Emission Units 1, 2, and 3), one permitted 2.8 million-gallon fuel oil storage tank (Emission Unit 4) and miscellaneous insignificant activities.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **347.0**	North (km): **3139.0**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **28 / 22 / 00**		Longitude (DD/MM/SS): **82 / 30 / 00**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **The Shady Hills Generating Station consists of three 170-MW dual-fuel, General Electric Frame 7FA combustion turbines that will use dry low-nitrogen oxide combustion technology when firing natural gas and water injection when firing distillate fuel oil. Only pipeline natural gas or maximum 0.05 percent sulfur No. 2 fuel oil will be fired in the CTs. The 3 CTs will operate no more than an average of 3,390 hours per yr, and no individual CT will operate more than 5,000 hours. The 3 CTs will operate no more than an average of 1,000 hours per unit on fuel oil during any calendar year. (See SH-FI-C10)**			

Facility Contact

1. Name and Title of Facility Contact: **Alan Dial, Control Room Operator**			
2. Facility Contact Mailing Address: Organization/Firm: **Shady Hills Generating Station**			
Street Address: **14240 Merchant Energy Way**			
City: **Shady Hills**	State: **FL**	Zip Code: **34610**	
3. Facility Contact Telephone Numbers: Telephone: **(727) 857 - 1787**		Fax: **(727) 857 - 1998**	

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **CTs are subject to NSPS Subpart GG. The fuel oil tank is subject to Subpart Kb.**	

List of Applicable Regulations

See Attachment SH-FI-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
PM	**A**				**Particulate Matter - Total**
VOC	**B**				**Volatile Organic Compounds**
SO_2	**A**				**Sulfur Dioxide**
NO_x	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxides**
PM_{10}	**A**				**Particulate Matter - PM_{10}**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID: SH-FI-C1 [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID: SH-FI-C2 [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID: SH-FI-C3 [ ] Not Applicable [ ] Waiver Requested
4.	Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: SH-FI-C4 [ ] Not Applicable [ ] Waiver Requested
5.	Fugitive Emissions Identification: [X] Attached, Document ID: SH-FI-C5 [ ] Not Applicable [ ] Waiver Requested
6.	Supplemental Information for Construction Permit Application: [ ] Attached, Document ID: ________ [X] Not Applicable
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [X] Attached, Document ID: SH-FI-C8 [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [X] Attached, Document ID: SH-FI-C10 [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [X] Attached, Document ID: SH-FI-C12 [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:________________________) [X] Not Applicable
14. Compliance Report and Plan: [X] Attached, Document ID: SH-FI-C14 [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [X] Attached, Document ID: SH-FI-C15 [ ] Not Applicable

ATTACHMENT SH-FI-A
LIST OF APPLICABLE REGULATIONS

[**Note:** The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

40 CFR 61, Subpart M: NESHAP for Asbestos.

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 06-01-01

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 06-21-01

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.
62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

Chapter 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 08-17-00

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-16-01

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-02-99

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 03-02-99

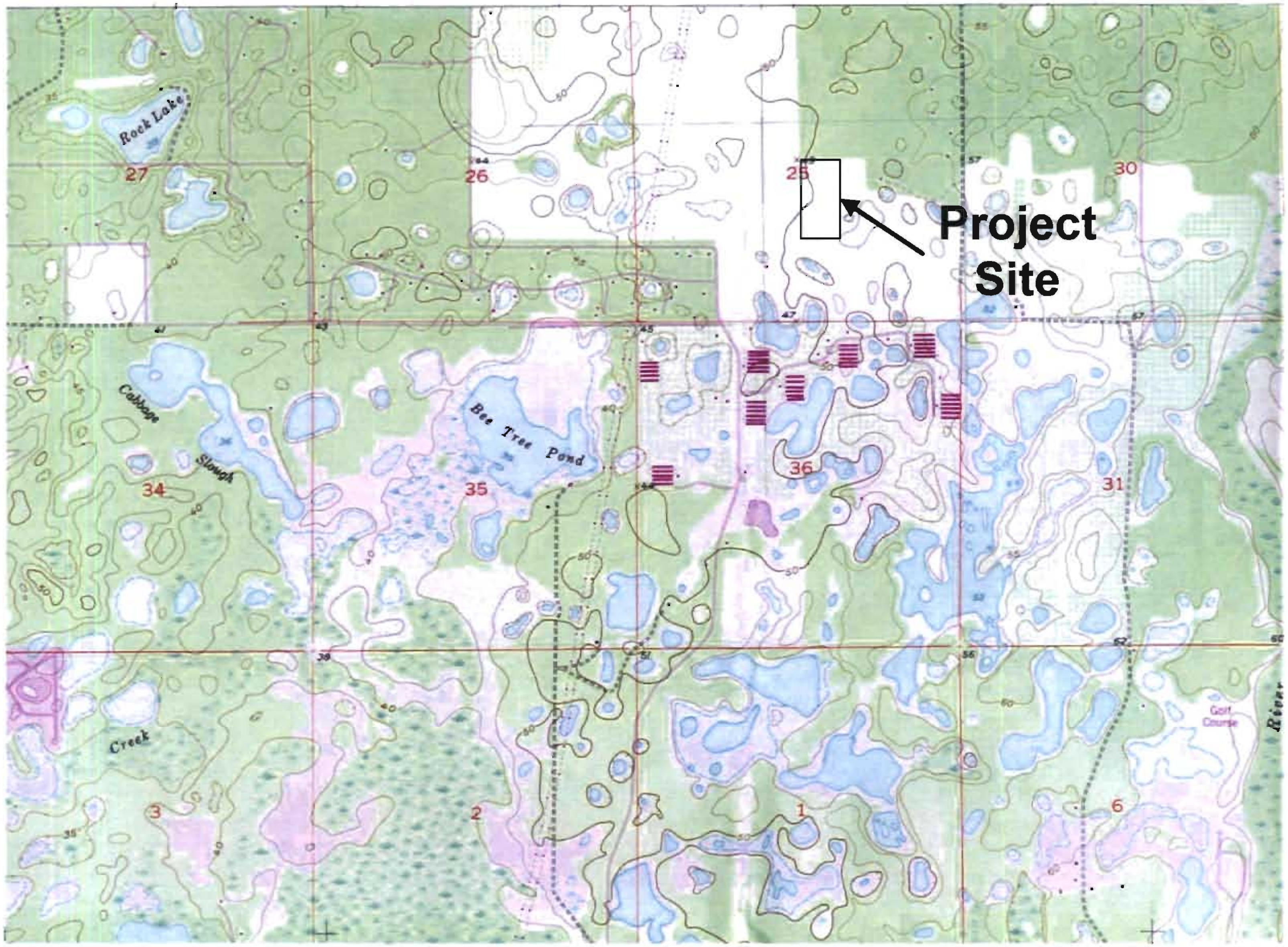
62-297.310, F.A.C.: General Test Requirements.
62-297.330, F.A.C.: Applicable Test Procedures.
62-297.340, F.A.C.: Frequency of Compliance Tests.
62-297.345, F.A.C.: Stack Sampling Facilities Provided by the Owner of an Emissions Unit.
62-297.350, F.A.C.: Determination of Process Variables.
62-297.570, F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

Miscellaneous:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
CHAPTER 62-256, F.A.C.: Open Burning and Frost Protection Fires, effective 11-30-94
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 02-09-99
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

ATTACHMENT SH-FI-C1

AREA MAP SHOWING FACILITY LOCATION

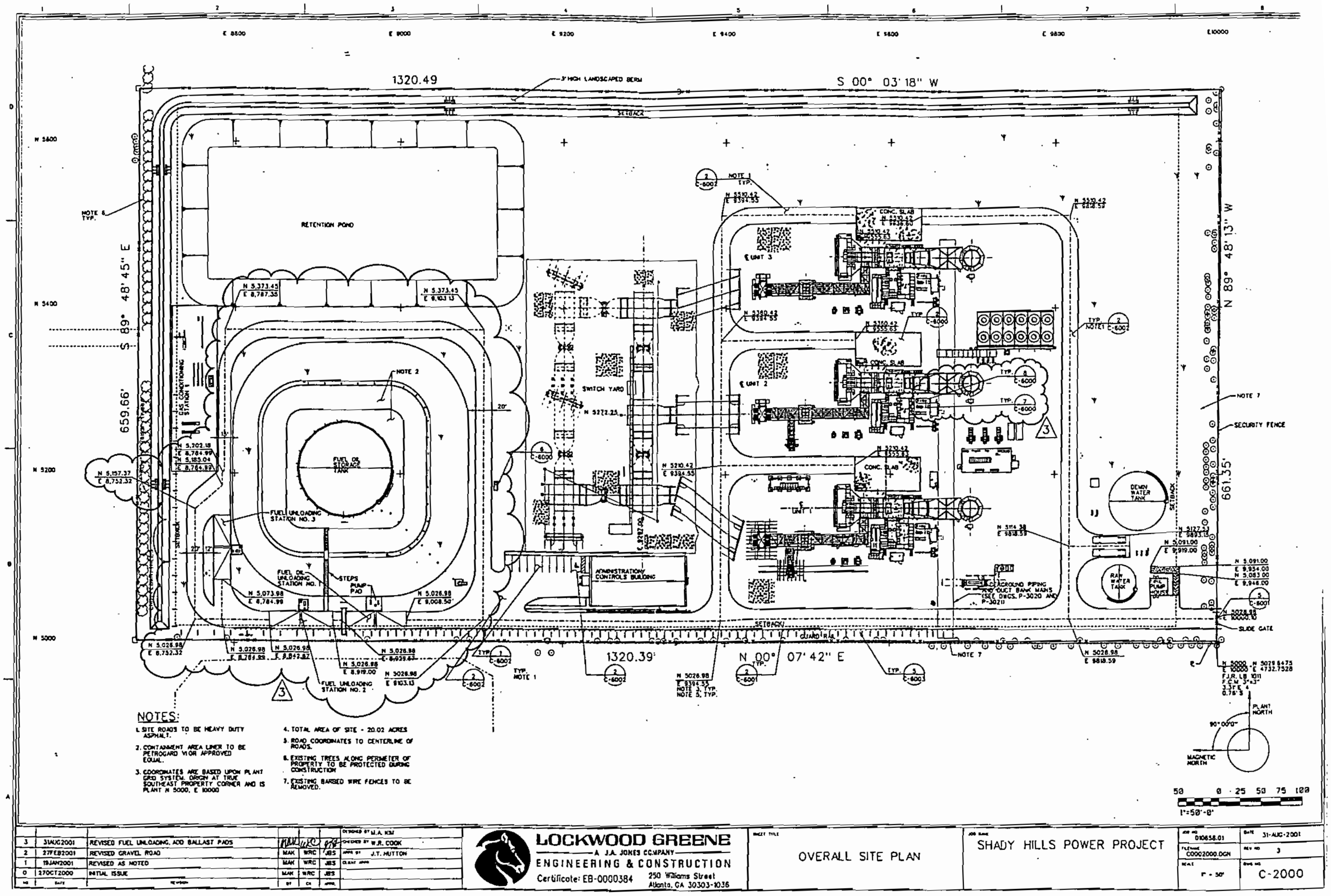


Attachment SH-FI-C1 Area Map Showing Facility Location
Shady Hills Generating Station

Source: Golder Associates Inc., 2001

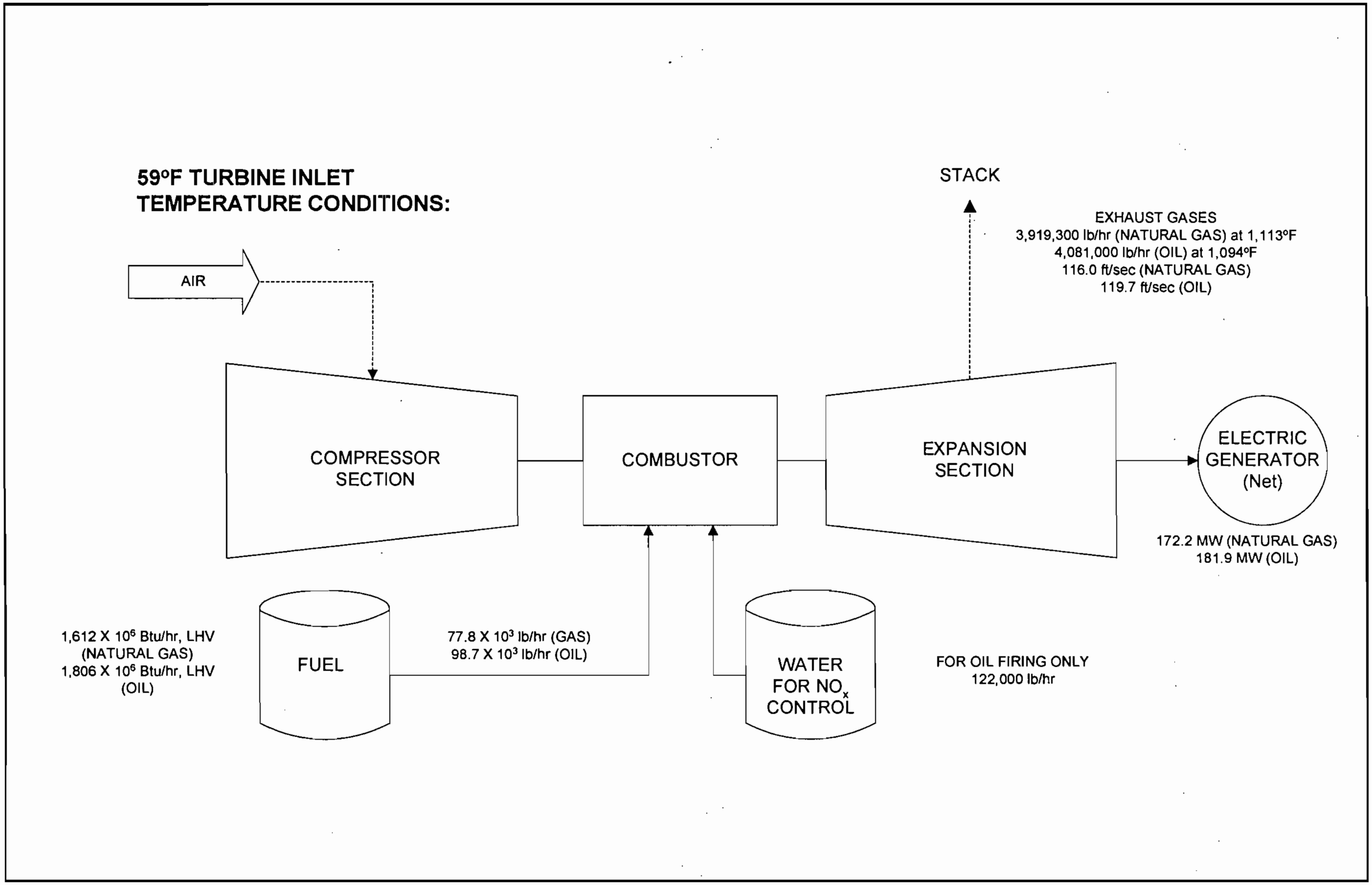
Golder Associates

ATTACHMENT SH-FI-C2
FACILITY PLOT PLAN


1320.49
S 00° 03' 18" W
RETENTION POND
SWITCH YARD
FUEL OIL STORAGE TANK
ADMINISTRATION/ CONTROLS BUILDING
UNIT 3
UNIT 2
UNIT 1
DEMIN WATER TANK
RAW WATER TANK
SECURITY FENCE
SLIDE GATE
1320.39'
N 00° 07' 42" E
S 89° 48' 45" E
659.66'
N 89° 48' 13" W
661.35'
FUEL UNLOADING STATION NO. 3
FUEL OIL UNLOADING STATION NO. 1
FUEL UNLOADING STATION NO. 2
PLANT NORTH
MAGNETIC NORTH
NOTES:
1. SITE ROADS TO BE HEAVY DUTY ASPHALT.
2. CONTAINMENT AREA LINER TO BE PETROGARD VI OR APPROVED EQUAL.
3. COORDINATES ARE BASED UPON PLANT GRID SYSTEM. ORIGIN AT TRUE SOUTHEAST PROPERTY CORNER AND IS PLANT N 5000, E 10000
4. TOTAL AREA OF SITE - 20.02 ACRES
5. ROAD COORDINATES TO CENTERLINE OF ROADS.
6. EXISTING TREES ALONG PERIMETER OF PROPERTY TO BE PROTECTED DURING CONSTRUCTION
7. EXISTING BARBED WIRE FENCES TO BE REMOVED.
1"=50'-0"
3 31AUG2001 REVISED FUEL UNLOADING, ADD BALLAST PADS
2 27FEB2001 REVISED GRAVEL ROAD MAK WRC JBS
1 19JAN2001 REVISED AS NOTED MAK WRC JBS
0 27OCT2000 INITIAL ISSUE MAK WRC JBS
DESIGNED BY M.A. KIM
CHECKED BY W.R. COOK
APPR BY J.T. HUTTON
LOCKWOOD GREENE
A J.A. JONES COMPANY
ENGINEERING & CONSTRUCTION
Certificate: EB-0000384
250 Williams Street
Atlanta, GA 30303-1036
OVERALL SITE PLAN
SHADY HILLS POWER PROJECT
010658.01
31-AUG-2001
C0002000.DGN
3
1" = 50'
C-2000

ATTACHMENT SH-FI-C3

PROCESS FLOW DIAGRAM



Attachment SH-FI-C3
Simplified Flow Diagram of GE Frame 7FA
Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 0139517/4/4.4/4.4.1/SH-FI-C3

Date: 3/29/02

Golder Associates

ATTACHMENT SH-FI-C4
PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT SH-FI-C4

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

- No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions.
- Any permit issued to this facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter.
- Reasonable precautions include the following:
  - Paving and maintenance of roads, parking areas and yards
  - Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
  - Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
  - Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne.
  - Landscaping or planting of vegetation.
  - Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
  - Confining abrasive blasting where possible.
  - Enclosure or covering of conveyor systems.
- In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

[Rule 62-296.320(4)(c), F.A.C.]

ATTACHMENT SH-FI-C5

FUGITIVE EMISSIONS IDENTIFICATION

ATTACHMENT SH-FI-C5
FUGITIVE EMISSIONS IDENTIFICATION

Many fugitive emissions at the plant site have been classified as "trivial activities". As a result, these activities are not included as part of this permit application. For example, emissions from general plant maintenance and upkeep activities at the facility would be considered fugitive emissions, but have been judged to be trivial since these activities are not conducted as part of the electricity generation process, not related to the source's primary business activity, and do not otherwise trigger a permit modification.

Fugitive emissions that may result from the operation of activities that are not trivial at the facility are addressed in the unregulated emissions unit section (Emission Unit 4). This emission unit section contains information on fugitive emissions that occur on a facility-wide basis. A summary of potential fugitive emission sources at the facility is presented in the following sections.

Criteria and Precursor Air Pollutants

Shady Hills has not identified fugitive emission of sulfur dioxide, nitrogen oxides, carbon monoxide, or lead compounds which would exceed the thresholds defined in the permit application instructions.

Volatile Organic Compounds (VOCs)

VOCs are emitted by the 2.8 million-gallon fuel oil storage tank and electrical equipment that uses fuel oil on the plant property. This includes a 2,000-gallon fuel oil tank, various lube oil tanks, various transformers, and the fuel oil unloading area. VOCs may also be emitted from the use of an acetylene torch unit in the maintenance building (insignificant unit).

Note: The 2,000 gallon fuel oil storage tank was originally permitted as a 1,000 gallon tank. This modifications has an insignificant effect on the unit's VOC emissions.

Particulate Matter (PM/PM_{10})

Particulate matter may be emitted as fugitive emissions in the maintenance building from the use of the following pieces of equipment (all insignificant units):

- Sand Blaster
- Welding Machine
- Bench Grinder
- Forklift
- Drill Press

ATTACHMENT SH-FI-C8

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES

ATTACHMENT DS-FI-C8

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES

Unregulated insignificant activities at the Shady Hills Generating Station include but are not limited to the following:

- Operation of a CO_2 based fire protection system to be used in case of emergency fire in or near the CTs.
- Operation of a Clarke diesel-based fire protection system for the building. Unit is rated at 265 BHP. See following page attachment for specifications.
- Operation of a 10 MMBtu/hr indirect fired fuel gas heater to prevent the natural gas from freezing. See following page attachment for specifications.
- Storage operations for the fuel oil storage locations described in Attachment SH-FI-C5 including the fuel oil truck unloading area.
- Miscellaneous maintenance, cleaning, and painting of the building including the control room, maintenance shop, storage warehouse, offices and their contents.
- Miscellaneous heaters.
- Miscellaneous general purpose internal combustion engines (i.e. cranes) for routine facility maintenance and/or equipment malfunctions.
- Surface coating operations; both >5% and 5% VOC.
- Demin water analyses operations to ensure proper operation of the water injection system and CT cooling processes.
- Stormwater retention basin maintenance (if required).

JDFP-06WA

FIRE PUMP DRIVER

EMISSION DATA

To complete an application for a Permit to Operate, the following data is provided.

6 *Cylinders*
Four *Cycle*
Lean *Burn*
Turbocharged & Aftercooled
Diesel Oil - *Fuel*
No - *Energy Recovery from Exhaust*
No - *Emission Control Device*

				G / HP / HR					%	EXHAUST		TIMING
RPM	BHP	FUEL GAL / HR	AIR/FUEL RATIO	HC	NOx	CO	SO_2	PART.	O_2	°F	CFM	DEGREES*
~~2100~~	~~275~~	~~14.8~~	~~31.70~~	~~0.28~~	~~6.0~~	~~0.28~~	~~0.60~~	~~0.08~~	~~10.7~~	~~750~~	~~1644~~	~~9.3~~
1760	265	14.2	26.31	0.23	6.7	0.29	0.67	0.07	9.5	840	1404	9.3
~~1470~~	~~220~~	~~13.2~~	~~20.01~~	~~0.32~~	~~6.7~~	~~0.29~~	~~0.73~~	~~0.07~~	~~5.8~~	~~990~~	~~1107~~	~~9.3~~

For specific RPM & BHP ratings, some of the above data may have been extrapolated from the best available test data.

Sulfur Dioxide based on 0.2% sulfur content in fuel (by weight).

**Degrees of Timing RETARD for 'Beginning of Injection' based on comparison with pre-emission controlled engines.*

6081A Base Model Engine Manufactured by John Deere Co.

CLARKE
FIRE PROTECTION PRODUCTS
3133 EAST KEMPER ROAD
CINCINNATI, OH 45241

FUEL GAS HEATER

SECTION III

THEORETICAL DESIGN CONDITIONS

I. COIL

Gas flow rate (#/Hr)	20,000-253,000.
Inlet pressure (PSIG)	450-500
Design pressure (PSIG)	550 max
Inlet temperature (Deg F)	25
Outlet temperature (Deg F)	85
Specific gravity (air = 1.0)	0.6
Pressure Drop (PSI)	8.0
Surface area (SQ. FT.)	1137.5
Connection size/type (IN.)	12" / 300# RFWN
Design pressure (PSIG)	550
Design temperature (Deg F)	-20/250

II. HEATER

Heater duty (MMBTU/HR)	10.0
Fire-tube flux rate @ duty (BTU/HR-SQ.FT.)	24,360
Bath temperature (Deg F)	205
Approximate initial bath charge (gallons)*	4,914.0

**At 60 Deg F.*

III. PRELIMINARY SET POINTS:

TAG #	SET POINT	DESCRIPTION
PCV-100	25 PSIG	First Cut Pressure Regulating Valve
PSV-100	40 PSIG	Fuel Gas Pressure Relief Valve
PCV-101	1.5 PSIG	Second Cut Pressure Regulating Valve
PCV-105	5 PSIG	Pilot Regulating Valve
PCV-103	80 PSIG	Pressure Regulating Valve
TIC-100	80 F	Process Temperature Controller
TIC-105	205 F	Bath Temperature Controller
TSHH-100	215 F	Bath High Temperature Shutdown
PSHH-100	10 PSIG	High Fuel Gas Pressure Shutdown
PSLL-100	0.5 PSIG	Low Fuel Gas Pressure Shutdown
PSLL-101	5" WC	Combustion Blower Pressure Switch

The above instrument settings are preliminary and are subject to change. Operating condition may change after start up which may require adjustment in instrument set points.

ATTACHMENT SH-FI-C10
ALTERNATIVE METHODS OF OPERATION

ATTACHMENT SH-FI-C10

ALTERNATIVE METHODS OF OPERATION

The combustion turbines (CTs) shall be fired primarily with low sulfur (maximum of 0.05 weight percent sulfur) No. 2 fuel oil or superior grade of distillate fuel oil and natural gas. The three stationary CTs will operate no more than an average of 3,390 hours per unit during any calendar year. The CTs will operate no more than an average of 1,000 hours per unit on fuel oil during any calendar year. No single CT will operate more than 5,000 hours in a single year. Potential and allowable emissions in this application do not reflect the maximum permitted emissions based on 5,000 hours per year operation on natural gas and/or 2,000 hours per year operation on fuel oil for a single CT. The operation of the CTs at baseload is as follows:

Fuel Oil Operation

The maximum heat input rate, based on the lower heating value (LHV) of No. 2 fuel oil at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure will not exceed 1,806 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. See III.B.6 in this application for overall maximum heat input rate and conditions.

The amount of fuel oil burned at this site (in BTU's) will not exceed the amount of natural gas burned at this site (in BTU's) during any consecutive 12-month period **[Rule 62-210.200, F.A.C. (BACT)]**.

Natural Gas Operation

The maximum heat input rate, based on the lower heating value (LHV) of No. 2 fuel oil at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure will not exceed 1,612 MMBtu/hr when firing natural gas. See III.B.6 in this application for overall maximum heat input rate and conditions.

ATTACHMENT SH-FI-C12
IDENTIFICATION OF ADDITIONAL APPLICABLE REQUIREMENTS

PERMITTEE:

IPS Avon Park Corporation
1560 Gulf Boulevard, # 701
Clearwater, Florida 32767

Permit No.	PSD-FL-280
File No.	1010373-001-AC
SIC No.	4911
Expires:	July 1, 2002

Authorized Representative:

John S. Ellis

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators; one 2.8-million gallon fuel oil storage tank; and three 60-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located East of Hudson and North of SR 52 in unincorporated, Pasco County. UTM coordinates are: Zone 17; 347.0 km E; 3139.0 km N.

STATEMENT OF BASIS:

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

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 60-foot stacks and one 2.8-million gallon fuel oil storage tanks. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSIONS UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	One 2.8 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- mm/dd/99 Notice of Intent published in ___________
- 11/30/99 Distributed Intent to Issue Permit
- 10/26/99 Application deemed complete
- 10/26/99 Received Application

RELEVANT DOCUMENTS:

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

- Application received on October 26, 1999
- Department's Intent to Issue and Public Notice Package dated November 30, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

SECTION II. ADMINISTRATIVE REQUIREMENTS

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southwest District office. [Chapter 62-213, F.A.C.]
9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District office by March 1st of each year. [Rule 62-210.370(2), F.A.C.]
11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]
13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Southwest District office. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of four 170 megawatt combustion turbines shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 004, Fuel Storage, consisting of one 2.8 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District.

GENERAL OPERATION REQUIREMENTS

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

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,612 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,806 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)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c)., F.A.C.]

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Southwest District as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: The stationary gas turbines shall only operate up to 3,390 hours per unit including up to 1000 hours on fuel oil during any calendar year. No single combustion turbine shall operate more than 5,000 hours in a single year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period [Rule 62-210.200, F.A.C. (BACT)]

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10/17 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC (not PSD)	As Above	1.4 ppmvd (Gas) 7 ppmvw (Fuel Oil)
CO	As Above	12 ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	1 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	9 ppmvd (Gas) 42 ppmvd (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:

- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppmvd @15% O_2 on a 24 hr block average (of valid hours during which the unit is operated only) as measured by the continuous emission monitoring system (CEMS). Refer to Condition 30 for valid hours contributing to the block average.

In addition, NO_X emissions calculated as NO_2 shall not exceed 64.1 pounds per hour (at ISO conditions) and 9 ppmvd @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. [Rule 62-212.400, F.A.C.]

- While firing Fuel Oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3-hr average (of valid hour hours during which the unit is actually operated only) as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 351 lb/hr (at ISO conditions) and 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

  The permittee shall develop a NO_X reduction plan when the hours of oil firing reach the allowable limit of 1000 hours per year. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. (BACT Determination].

20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd and 42.5 lb/hr (at ISO conditions) while firing gas and neither 20 ppmvd and 71.4 lb/hr (at ISO conditions). The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.4 ppmvd nor 2.8 lb/hr (ISO conditions) and neither 7 ppmvw nor 16.2 lb/hr (ISO conditions) while operating on oil to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Applicant Request to Avoid PSD, Rule 62-212.400, F.A.C.]

22. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 1 grain per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year per unit. Emissions of SO_2 (at ISO conditions) shall not exceed 5 lb/hr (natural gas) and 98.7 lb/hr (fuel oil) as measured by applicable compliance methods described below. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]

23. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 10 lb/hr when operating on natural gas and shall not exceed 17 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

24. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions and shall not exceed 10 opacity. Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).

26. Excess emissions 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 emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District 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. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).

- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements).
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as required in Conditions 25 and 26. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

    - All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These 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]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. 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.

35. Test Notification: The DEP's Southwest District 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).

36. 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.

37. Test Results: Compliance test results shall be submitted to the DEP's Southwest District no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by IPSAPC 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.

39. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition No.36 above. 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.

MONITORING REQUIREMENTS

40. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on these Units 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, 40 CFR 75and 40 CFR 60.7 (1998 version)].

41. CEMS for reporting excess emissions: Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions No 18 and 19, shall be reported to the DEP Southwest District within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).

42. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS

43. Continuous Monitoring 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.

44. Natural Gas Monitoring Schedule: 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 pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

- Each unit shall be monitored for SO_2 emissions 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 pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

45. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

ATTACHMENT SH-FI-C14
COMPLIANCE REPORT AND PLAN

ATTACHMENT SH-FI-C14

COMPLIANCE REPORT AND PLAN

Compliance with the conditions set forth in this operation permit will be certified on an annual basis by the submittal of the Statement of Compliance – Title V Source DEP Form No. 62-213.900(7). This report will be submitted by March 1 of each year for the prior calendar year.

ATTACHMENT SH-FI-C15

COMPLIANCE CERTIFICATION

ATTACHMENT SH-FI-C15

COMPLIANCE CERTIFICATION

The facility and emission units identified in this application are in compliance with the Applicable Regulations identified in the application form and attachments referenced in the section. The compliance report for this facility will be submitted by March 1 of each year for the prior calendar year. The compliance statement is as follows:

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

James Packer
Signature, Responsible Official

03-28-02
Date

James Packer, Director of Operations, Southeast Business Unit

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

GE Frame 7FA Combustion Turbine

4. Emissions Unit Identification Number: [ ] No ID
ID: **001** [ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **February 2002**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

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

This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment SH-EU1-A9.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_x combustion - Natural gas firing** **Water injection - Distillate oil firing**	
2. Control Device or Method Code(s): **25, 28**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** 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:		1,858	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		days/week
	weeks/year	5,000	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum heat input at 100% load and 32°F oil firing (LHV).
Maximum for gas firing is 1,670 MMBtu/hr at 100% load and 32°F (LHV).
The CTs will operate no more than an average of 3,390 hrs/CT/yr.
No single CT will operate > 5,000 hrs per year.
See Attachment SH-EU1-B6 for performance specifications and emissions guarantees.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment SH-EU1-D	

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? **CT1**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,645,000**	10. Water Vapor: **8.6** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **347.0** North (km): **3139.0**	
14. Emission Point Comment (limit to 200 characters): **Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.**	

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): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **13.7**	5. Maximum Annual Rate: **13,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 131.8 (rounded to 132). Based on 7.1 lb/gal; LHV of 18,560 Btu/lb, ISO conditions, 1,000 hrs/yr operation. The amount of fuel oil burned (BTU's) will not exceed the amount of natural gas burned (BTU's) per year.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.70**	5. Maximum Annual Rate: **5,752**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025	028	EL
CO			EL
VOC			EL
PM_{10}			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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 **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 grain/100 cf - 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 1998; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See PSD Air Construction Permit Application; Section 2.0; Appendix A.

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

   Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.

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: **42 ppmvd**
4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters):

   3-Hour Average

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

   Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **24-Hour Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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**	4. Equivalent Allowable Emissions: **74.4** lb/hour **35.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **7 ppmvw**	4. Equivalent Allowable Emissions: **16.7** lb/hour **8.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 – CO Test**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 – CO Test**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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 **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other **(BACT)**
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **VE Test serves as a surrogate for PM/PM_{10} compliance testing.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Horiba** Model Number: **ENDA-E4220LS**	Serial Number: **11527**
5. Installation Date: **01 Nov 2001**	6. Performance Specification Test Date: **15 Feb 2002**
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **2 hrs/24 hrs** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-210.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Horiba** Model Number: **ENDA-E4220LS**	Serial Number: **11527**
5. Installation Date: **01 Nov 2001**	6. Performance Specification Test Date: **15 Feb 2002**
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: Water/Fuel Ratio. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1.	Process Flow Diagram [X] Attached, Document ID: SH-EU1-J1 [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: SH-EU1-J2 [ ] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [X] Attached, Document ID: SH-EU1-J3 [ ] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [X] Attached, Document ID: SH-EU1-J4 [ ] Not Applicable [ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ______ [X] Previously submitted, Date: 2/28/02 [ ] Not Applicable
6.	Procedures for Startup and Shutdown [X] Attached, Document ID: SH-EU1-J6 [ ] Not Applicable [ ] Waiver Requested
7.	Operation and Maintenance Plan [X] Attached, Document ID: SH-EU1-J7 [ ] Not Applicable [ ] Waiver Requested
8.	Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ______ [X] Not Applicable
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID: ______ [X] Not Applicable
10.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [X] Not Applicable

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

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

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

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

[X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID: **SH-EU1-J15**

[ ] 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

ATTACHMENT SH-EU1-A9

EMISSIONS UNIT COMMENT

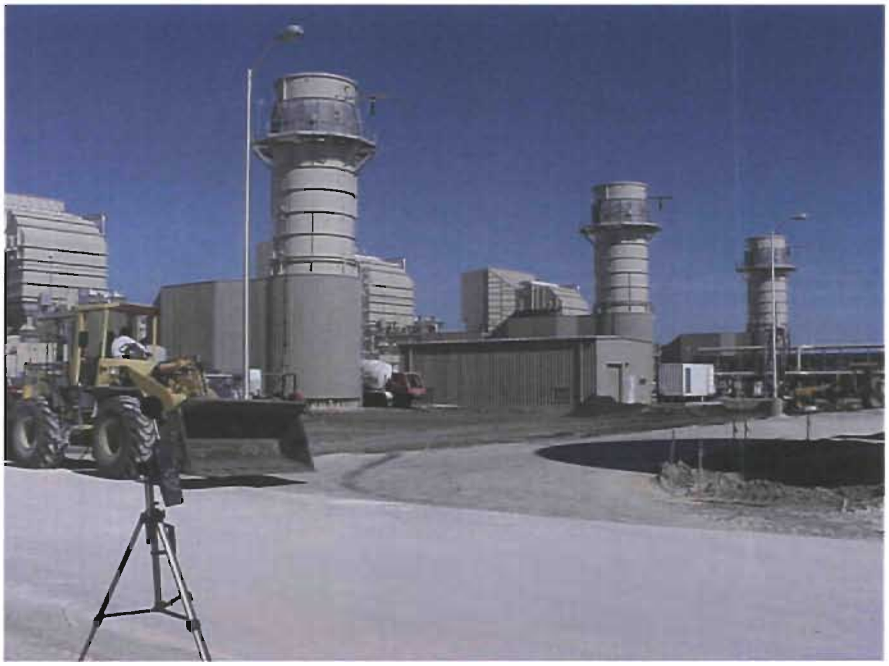


Photo 1. Diagonal View - Combustion Turbine

Photo 2. Front View - Combustion Turbine

Attachment SH-EU1-A9
Shady Hills Generating Station Photos

Source: Golder, 2002.

Golder Associates

ATTACHMENT SH-EU1-B6

OPERATING CAPACITY/SCHEDULE COMMENT

2. Performance Guarantees

2.1 Guaranteed Performance

Operating Point	Fuel	Output (kW)	Heat Rate (Btu/kWh, LHV)
Baseload, 95°F, 64% RH	Natural Gas	154,100	9,680
Baseload, 95°F, 64% RH	Distillate Oil	165,500	10,150
Heat Rate = Fuel Consumption (Btu/h, LHV) / Output (kW)			

2.1.1 Basis For Equipment Performance

The performance guarantees listed above are based on the scope of equipment supply as defined in this proposal and as stated for the following operating conditions and cycle parameters:

a. The natural gas fuel and distillate fuel oil are in compliance with Seller's Gas Fuel Specification GEI-41040F and Liquid Fuel Specification 41047H respectively and supplementary Fuel, Air and Steam Purity Requirements as defined in this proposal.

b. Natural Gas Fuel Heating Value = 20,773 Btu/lb (LHV)

c. Distillate Fuel Oil Heating Value = 18,300 Btu/lb (LHV)

d. Site Elevation = 50 ft

e. Site Pressure = 14.67 psia.

f. Inlet Loss = 4.0 in Water

g. Exhaust Loss = 5.5 in Water

h. Evaporative Cooler = On, with 85% effectiveness

i. Fuel Gas Supply Temperature = 80°F (@ GT stop valve)

j. Fuel Gas Supply Pressure = 450 psig - 475 psig (@ GT stop valve)

k. Gas turbines are operating at steady state baseload.

l. Tests to demonstrate guaranteed performance shall be conducted in accordance with the ASME Performance Test Procedure as defined in this proposal (GEK-41067D).

m. Generator power factor for baseload operation = .85 lagging.

n. Performance is measured at the generator terminals and includes allowances for excitation power and the shaft-driven equipment normally supplied.

o. Station services for GE supplied auxiliaries are not included in the guaranteed performance.

p. The equipment is in a new and clean condition (less than 100 fire hours of operation).

q. Performance curves such as ambient effects curves and generator efficiency curves will be provided after contract award. These curves are to be used during the site performance test to correct performance readings back to the site conditions at which the performance guarantees were provided. Where available, typical correction curves have been supplied.

r. Natural gas performance is based on operation with a dry low NOx combustion system without gas turbine diluent injection for NOx control.

s. Distillate fuel oil performance is based on diluent injection flow rate of 93,890 lb/hr. The actual amount of diluent injection as determined during the field compliance test may be different, which will have an effect on the output and heat rate.

t. Compressor air extraction from gas turbine = 0.

u. Natural Gas Analysis (%vol) =

Nitrogen	0.2441	Propane	0.8050	Pentane	0.0329
CO2	0.9672	I-Butane	0.1956	Hexane	0.0855
Methane	94.7081	Butane	0.1754		
Ethane	2.7296	I-Pentane	0.0565		

v. A nominal distillate oil analysis was assumed for the guarantees.

2.2 Emissions Guarantees

Exhaust gas emissions shall not exceed the following concentrations during steady-state operation from baseload down to 50% CT load over the ambient temperature range from 20°F to 100°F for each of the gas turbines:

	Natural Gas	Distillate Oil
NOx, ppmvd Ref. 15% O_2, ISO	9	42
CO, ppmvd	12	20
VOC, ppmvw	1.4	3.5
Particulates (TSP - front half only), lb/hr	9	17
Opacity	10%	20%

2.2.1 Basis For Emissions Guarantees

a. The natural gas fuel and distillate fuel oil are in compliance with Seller's Gas Fuel Specification GEI-41040F and Liquid Fuel Specification 41047H respectively and supplementary Fuel, Air and Steam Purity Requirements as defined in this proposal.

b. Testing and system adjustments are conducted in accordance with GEK-28172F, Standard Field Testing Procedure for Emissions Compliance included in the Reference Specifications/Documents Tab of this proposal.

c. Ambient air pressure = 14.67 psia

d. Emissions are per gas turbine on a one hour average basis.

e. Fuel bound nitrogen = 0% on NG; maximum of 0.015% (by wt) on distillate fuel oil

f. Fuel ash content = 0%

g. Sulfur emissions are a function of the sulfur present in the incoming air and fuel flows. Since the gas turbine(s) have no influence on the sulfur emissions when no sulfur is present in the fuel, sulfur based emissions are not guaranteed

h. GE reserves the right to determine the emission rates on a net basis wherein emissions at the gas turbine inlet are subtracted from the measured exhaust emission rate if required to demonstrate guarantee rate.

ATTACHMENT SH-EU1-D
APPLICABLE REQUIREMENTS

ATTACHMENT SH-EU1-D

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	NSPS Subpart GG
62-204.800(7)(c) (State Only)	NSPS authority
62-204.800(7)(d)(State Only)	NSPS General Provisions
62-204.800(12) (State Only)	Acid Rain Program
62-204.800(13) (State Only)	Allowances
62-204.800(14) (State Only)	Acid Rain Program Monitoring
62-204.800(16) (State Only)	Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	Circumvention; EUs with control device
62-210.700(1)	Excess Emissions;
62-210.700(4)	Excess Emissions; poor maintenance
62-210.700(6)	Excess Emissions; notification

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320	All Acid Rain Units (Application Shield)
62-214.330(1)(a)	Compliance Options (if 214.430)
62-214.340	Exemptions (retired units)
62-214.350(2);(3);(5);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)	All Units (Operating Rate)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)	All Units (Applicable Test Procedures)
62-297.310(5)	All Units (Determination of Process Variables)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)
62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels

62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.	Annual Test
62-297.310(7)(a)5.	PM exemption if <400 hrs/yr
62-297.310(7)(a)8.	VE Compliance Test if > 400 hrs/yr
62-297.310(7)(a)9.	FDEP Notification - 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:	
40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:	
40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Requirements
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(d)	Performance Test Notification
40 CFR 60.8(e)	Provide Stack Sampling Facilities

40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention
40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)

Acid Rain-Permits:	
40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iv)	SO_2 Allowances-Phase II Units
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS

40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID;unit/system ID
40 CFR 72.33(c)	Dispatch System ID;ID requirements
40 CFR 72.33(d)	Dispatch System ID;ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	Compliance Dates;
40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(c)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)

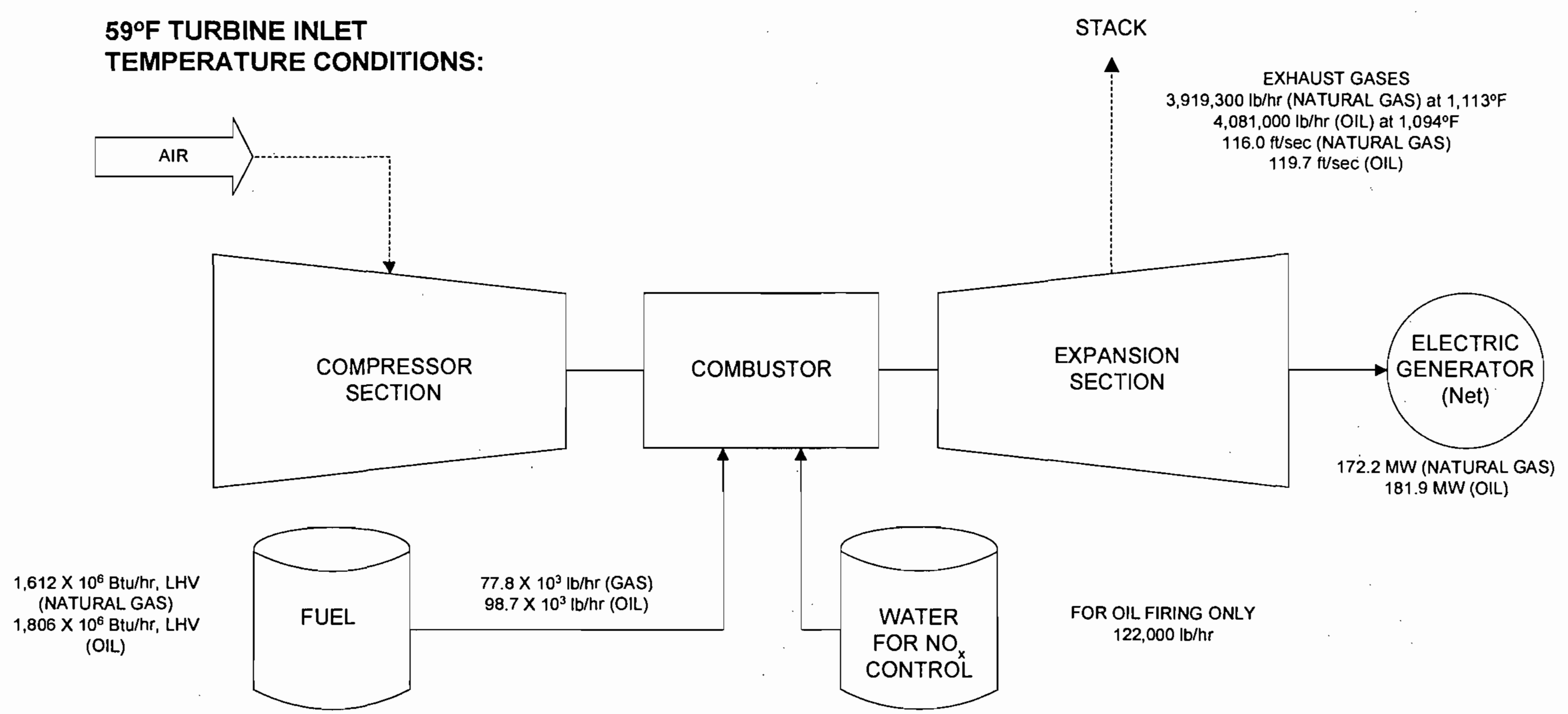
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; CO_2
40 CFR 75.30(d)	General Missing Data Procedures; SO_2
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.53	Monitoring Plan; revisions
40 CFR 75.57(a)	Recordkeeping Requirements for Affected Sources
40 CFR 75.57(b)	Operating Parameter Record Provisions
40 CFR 75.57(d)	NO_x Emission Record Provisions
40 CFR 75.57(e)	CO_2 Emission Record Provisions
40 CFR 75.57(h)	Missing Data Records
40 CFR 75.58(c)	Specific SO_2 Emission Record Provisions
40 CFR 75.58(e)	Specific SO_2 Emission Record Provisions
40 CFR 75.59	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.64(f)	Method of Submission
40 CFR 75.64(g)	Submission Requirements
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A	Specifications and Test Procedures
Appendix B	QA/QC Procedures
Appendix C.	Missing Data Estimation Procedures
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures

Acid Rain Program-Excess Emissions:

40 CFR 77.3	Offset Plans
40 CFR 77.5(b)	Deductions of Allowances
40 CFR 77.6	Excess Emissions Penalties (SO_2)

ATTACHMENT SH-EU1-J1

PROCESS FLOW DIAGRAM



Attachment SH-EU1-J1
Simplified Flow Diagram of GE Frame 7FA
Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid ⟶
Gas ⇢
Steam ⟶

Filename: SH-EU1-J1
Date: 3/29/02

Golder Associates

ATTACHMENT SH-EU1-J2
FUEL SPECIFICATION
NO. 2 FUEL OIL

Table 2 - Liquid Fuel Specifications							
				True Distillates (b)		Ash-Bearing Fuels (b)	
Applicability	**Property**	**Point of Applicability (a)**	**ASTM Test Method (c)**	**Light**	**Heavy**	**Crudes and Blended Residual Fuels**	**Heavier Residual Fuels**
3.1 Gas Turbine Requirements	Kin. Viscosity, cSt, 100°F (37.8°C), min	Delivery	D445	.5(d)	1.8	1.8	1.8
	Kin. Viscosity, cSt, 100°F (37.8°C), max (e)	Delivery	D445	5.8	30	160	900
	Kin. Viscosity, cSt, 210°F (98.9°C), max (e)	Delivery	D445	—	4	13	30
	Specific Gravity, 60°F (15.6°C), max	Delivery	D1298	Report	Report	.96	.96(f)
	Flash Point, °F(°C), min (g)	Delivery	D93	Report	Report	Report	Report
	Distillation Temp. 90% Point, °F(°C), max	Delivery	D86	650(338)	Report	—	—
	Pour Point, °F(°), max	Delivery	D97	0 (-18) or 20 (7) below min. ambient	Report	Report	Report
	Hydrogen, Wt %, min (k)	Delivery	(i)	Report	Report	Report	Report
	Carbon Residue, Wt. % (10% Bottoms) max Direct Pressure Atomization	Delivery	D524	.25	—	—	—
	Carbon Residue, Wt. % (100% Sample) max Air Atomization, Low Pressure	Delivery	D524	1.0	1.0	1.0	—
	Carbon Residue, Wt. % (100% Sample), Air Atomization, High Pressure	Delivery	D524	—	—	Report	Report
	Ash, ppm, max	Combustor	D482	50	50	Report	Report
	Trace Metal Contaminants, ppm, max (h)	Combustor	(i)				
	Sodium plus Potassium			1	1	1	1
	Lead			1	1	1	1
	Vanadium (untreated)			.5	.5	.5	.5
	Vanadium (treated 3/1 wt. ratio Mg/V)			—	—	100	500
	Calcium			2	2	10	10
	Other Trace Metals above 5 ppm			Report	Report	Report	Report
The specifications below apply only when specific environmental codes exist							
3.2 Environmental Code Related Requirements	Sulfur, Wt. %, max	Delivery	D129	Compliance to any applicable codes.			
	Nitrogen, Wt. %, max	Delivery	(i)	Fuel-bound nitrogen may be limited to meet any applicable codes on total NO_x emission.			
	Hydrogen, Wt. %, min.	Delivery	(i)	Minimum hydrogen level may be necessary to meet any applicable stack plume opacity limits (k).			
	Ash plus Vanadium, ppm, max.	Delivery	(i)	Ash plus vanadium content of ash-bearing fuels may be limited to meet applicable stack particulate emission codes (l).			

NOTES TO TABLE 2

a. The fuel properties specified refer to the fuel at different points in the overall system:
Delivery — Fuel as delivered to the turbine site.
Fuel Skid — Fuel at inlet of fuel skid at turbine.
Combustor — Fuel at turbine combustors.

b. Typical fuels within each general type are discussed in Appendix A.

c. ASTM Book of Standards, Parts 23 and 24.

d. In the viscosity range of 0.5 cSt to 1.8 cSt, special fuel pumping equipment may be required.

e. The maximum allowable viscosity at the fuel nozzle is 20 cSt for high pressure air atomization and 10 cSt for low pressure air and direct pressure atomization. The fuel may have to be preheated to reach this viscosity, but in no instance shall it be heated above 275°F (135°C). (This maximum fuel temperature of 275°F is allowed only with residual fuels.) The viscosity of the fuel at initial light-off must be at or below 10 cSt.

f. A specific gravity of 0.96 is based on average fuel desalting capability with standard washing systems. Fuels with specific gravities greater than 0.96 may be desalted to the required minimum sodium plus potassium limits by using higher capability desalting equipment (with higher attendant cost) or by increasing the gravity difference between the fuel and wash water by blending the fuel with a compatible distillate.

g. The fuel must comply to all applicable codes for flash point.

h. A total ash less than 3 ppm is acceptable in place of trace metal analysis.

i. No standard reference tests exist; methods used should be mutually acceptable to General Electric and the user.

j. Water content of crude oils should be reduced to the lowest level practical consistent with capability of available fuel treatment equipment, to minimize the chance of corrosion of fuel system components. In no case shall the water content exceed 1.0 vol. %.

k. A minimum hydrogen content is set both to control flame radiation in the combustor and to limit smoke emissions, where the latter is required by local codes. The limits are 12.0% minimum for true distillates and 11.0% for Ash-bearing fuels (11.3% where the carbon residue exceeds 3.5%). In each case it is assumed that the proper combustor and fuel atomization system are used.

Where the hydrogen content of the fuel is below these limits, General Electric should be consulted for appropriate action.

l. Local codes on total stack particulate emissions may set an upper limit on the sum of the ash (non-filterable) in the original fuel plus the vanadium content. The vanadium together with the required magnesium inhibitor may be a major contributor to total stack particulate emissions. In estimating these emissions for comparison with the code, all of he following sources may have to be considered: vanadium, additives, fuel ash and total sulfur in the fuel; non-combustible particulates in the inlet air; solids from any injected steam or water; and particles from in-

ATTACHMENT SH-EU1-J2

FUEL SPECIFICATION

NATURAL GAS

TABLE 2
GAS FUEL SPECIFICATION

FUEL PROPERTIES	MAX		MIN		NOTES
Lower Heating Value, Btu/lb	None		100 – 300		See note 3
Modified Wobbe Index Range	+5%		–5%		See Notes 4,5
Superheat, °F	–		50		See Note 6
Flammability	See Note 7		>2.2:1		Rich to lean fuel to air ratio, volume basis See Note 8
Gas Constituent Limits, % by volume:					
Methane	100		85		% of reactant species
Ethane	15		0		% of reactant species
Propane	15		0		% of reactant species
Butane + Paraffine (C4+)	5		0		% of reactant species
Hydrogen	0		0		% of reactant species
Carbon Monoxide	15		0		% of reactant species
Oxygen	10		0		% of reactant species
Carbon Dioxode	15		0		% total (reactants + inerts)
Nitrogen	30		0		% total (reactants + inerts)
Sulfur	–		–		See Note 9
Total Inerts (N_2 + CO_2+AR)	30		0		
Aromatics (Benzene, Toluene etc.)	Report		0		See Note 10
Gas Fuel Supply Pressure					See Note 11
CONTAMINANTS (See Notes 12,13)	**FUEL LIMITS** ppmw (See Note 14)				**NOTES**
Particulate	MS3000 MS5000	B/E Class	F Class	H Class	See Note 15
Total	35	32	23	23	
Above 10 Microns	0.4	0.3	0.2	0.2	
Trace Metals Sodium plus potassium	0.8				See Note 16
Liquids	0				No Liquids allowed, see superheat requirements and Note 17

Notes:

1. All fuel properties must meet the requirements from ignition to base load unless otherwise stated.
2. Values and limits apply at the inlet of the gas fuel control module.
3. Heating value ranges shown are provided as guidelines. Specific fuel analysis must be furnished to GE for proper analysis. (Reference Section III-A)
4. See section III-B. for definition of Modified Wobbe Index Range.

ATTACHMENT SH-EU1-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

This attachment provides a general description of the water injection system's operation as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU1-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

GENERAL

The water injection system provides water to the combustion system of the gas turbine to limit the levels of nitrogen oxides (NOX) in the turbine exhaust. This limitation is required by strict local and federal regulations. The water injection system schedules water flow to the turbine as a function of total fuel flow, relative humidity, and ambient temperature. The required water/fuel ratio is established through field compliance testing of the individual turbine. A final control schedule based on these tests is programmed in the SPEEDTRONICE control, which then regulates the system. The water injection system consists of both on-base components and an off-base water injection skid. This skid is a factory assembled and enclosed package. It receives water from the customer's treatment facility, and delivers filtered water at the pressure and flow rate required to meet the applicable emissions requirement at that operating condition. The filtered water is introduced to the turbine combustion system through a water supply manifold. The manifold supplies water to each of the 14 combustors on the gas turbine. The manifold inlet connection is located on the turbine base. The water is injected through identical nozzles in each of the combustors. The following is a brief functional description of the system as well as a control and monitoring description. More detailed information on individual items is given in the manufacturer's literature (Equipment Publications).

FUNCTIONAL DESCRIPTION

The water injection system supplies treated and filtered water at the required flow rate and pressure to the combustion system of the gas turbine. Water enters the skid and passes through a strainer (FW1-2), which protects the system components from damage by foreign objects. A pressure switch (63WN-1) senses pressure upstream of the Pump. The SPEEDTRONICE control system will trip the pump motor if the pressure sensed by this switch is too low. This protects the pump from damage due to cavitation. An electric motor (88WN-1) drives the centrifugal water injection pump (PW1-1). The speed of the electric motor is controlled by a Variable Frequency Drive unit or VFD (97WN-1). The VFD modulates the frequency of the AC power supplied to the motor (88WN-1). By varying the frequency of the AC power, the pump speed can be precisely controlled. By varying the pump speed, the pump discharge pressure, and hence the discharge flow rate are controlled. The VFD controls the pump speed in response to a 4-20 mA

demand signal from the SPEEDTRONICE. A 0-10 V speed feedback signal (96WN-4) from the VFD is fed back to the SPEEDTRONICE□ for monitoring and fault detection purposes.

A discharge pressure transmitter (96WP-1) is located downstream of the pump. The signal from this transmitter is fed back to the SPEEDTRONICE □ for monitoring and fault detection. The flow then passes through a high pressure filter assembly (FW1-1). The filter elements are contained in a high pressure filter housing, with a vent and drain. A differential pressure gauge indicates the pressure drop across the filter. A differential pressure switch (63WN-3) also senses the differential pressure across the filter, and signals an alarm in the SPEEDTRONICE control if the pressure differential exceeds the pressure specified in the device summary. Downstream of the filter, the flow is split into a main line to the turbine, and a recirculation line, which returns to the pump inlet upstream of the inlet strainer via the "cascade" recirculation orifice. The recirculation flow allows the pump to run in a stable and safe condition when there is little or no flow being delivered to the turbine. It is important that the pump is not run only on recirculation flow for an extended period of time. Extended running on pump recirculation only may cause overheating of the pump, or damage to the pump seals. The water flow in the main line next passes through a turbine flowmeter (FM1-1), with triple pick-ups, each with its own Flow Transmitter (96WF-1, 96WF-2, and 96WF-3). The flowmeter provides a signal to the SPEEDTRONICE control system. A strainer (FW1-3) is installed downstream of the flowmeters, to protect the other system components in the event of a flowmeter failure. Manually operated bypass/isolation valves, and a bypass piping loop is provided to allow the flowmeter to be isolated (e.g. for flushing) or to be removed for maintenance (if necessary). Downstream of the flowmeters, the flow passes through a water actuated stop valve (VS2-1), with solenoid control valve (20WN-1), which shuts off water flow in response to a command from the control system. Downstream of the stop valve is a manual isolation valve, followed by the skid discharge connection ("WJ2"). Interconnecting piping (provided by the customer) carries the water flow from the skid discharge to the manifold connection on the turbine base ("WI2"). The manifold distributes flow equally to fourteen flow proportioning valves (VWP1-1 to 14). These valves have a 15 psid (1.0 kg/cm2) cracking pressure, and provide a graduated flow restriction such that the flow resistance is relatively high at low flows. The purpose of the flow proportioning valves is to provide an even flow distribution at start-up and at low flows. The discharge from each of these valves is connected to tubing, which carries the flow of water to one of the combustors.

CONTROL AND MONITORING

Total water flow to the turbine is scheduled as a function of fuel flow to the turbine. A control schedule must be established during field compliance tests to meet emissions limits specified by the applicable local or federal standards. The compliance curve, determined as a result of these tests, is programmed into the SPEEDTRONICE control system. It is used as a reference for comparison to the actual water flow, in order to verify that emissions regulations are being met.

The electronic controllers (micro-computers R, S, and T) in the SPEEDTRONICE, control the flow of water in accordance with the control schedule and compliance control curve. The controllers generate a 4 to 20 mA demand signal to the Variable Frequency Drive, which accurately modulates pump speed to obtain the required flow. The control signal is generated in accordance with the control schedule, to achieve the required emissions levels at that particular operating condition. The skid flowmeter (FM1-1) generates a 4 to 20 mA output proportional to flow rate, which the SPEEDTRONICE uses in the flow control loop as a feedback signal.

ATTACHMENT SH-EU1-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

FUEL GAS CONTROL SYSTEM (DLN_X 2.6)

This attachment provides a general description of Dry Low NO_X system's operation as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU1-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

FUEL GAS SYSTEM (DLN 2.6)

GENERAL

The Stop/Speed Ratio Valve (SRV) and the Gas Control Valves (GCVs) work in conjunction to regulate the total fuel flow delivered to the gas turbine. This arrangement uses four separate Gas Control Valves to control the distribution of the fuel flow to a multi-nozzle combustion system. (See Gas Fuel System schematic) The GCVs control the desired fuel flow in response to a control system fuel command, Fuel Stroke Reference (FSR). The response of the fuel flow to GCVs' commands is made predictable by maintaining a predetermined pressure upstream of the GCVs. The GCVs' upstream pressure, P2 , is controlled by modulating the SRV based on turbine speed as a percentage of full speed, TNH, and feedback from the P2 pressure transducers, 96FG-2A, B, and C. Refer to the Gas Fuel System schematic. In a Dry Low NOx 2.6 (DLN-2.6) combustion system there are four gas fuel system manifolds: Premix 1 (PM1), Premix 2 (PM2), Premix 3 (PM3), and Quarternary (Q). Each combustion chamber has a total of six fuel nozzles. The PM1 gas fuel delivery system consists of one diffusion type fuel nozzle for each combustion chamber. The PM2 gas fuel delivery system consists of two premix type fuel nozzles for each combustion chamber. The Quarternary gas fuel delivery system consists of injection pegs located in each combustion casing. The PM3 gas fuel delivery system consists of three premix type fuel nozzles for each combustion chamber. The GCVs regulate the percentage of the total fuel flow delivered to each of the gas fuel system manifolds.

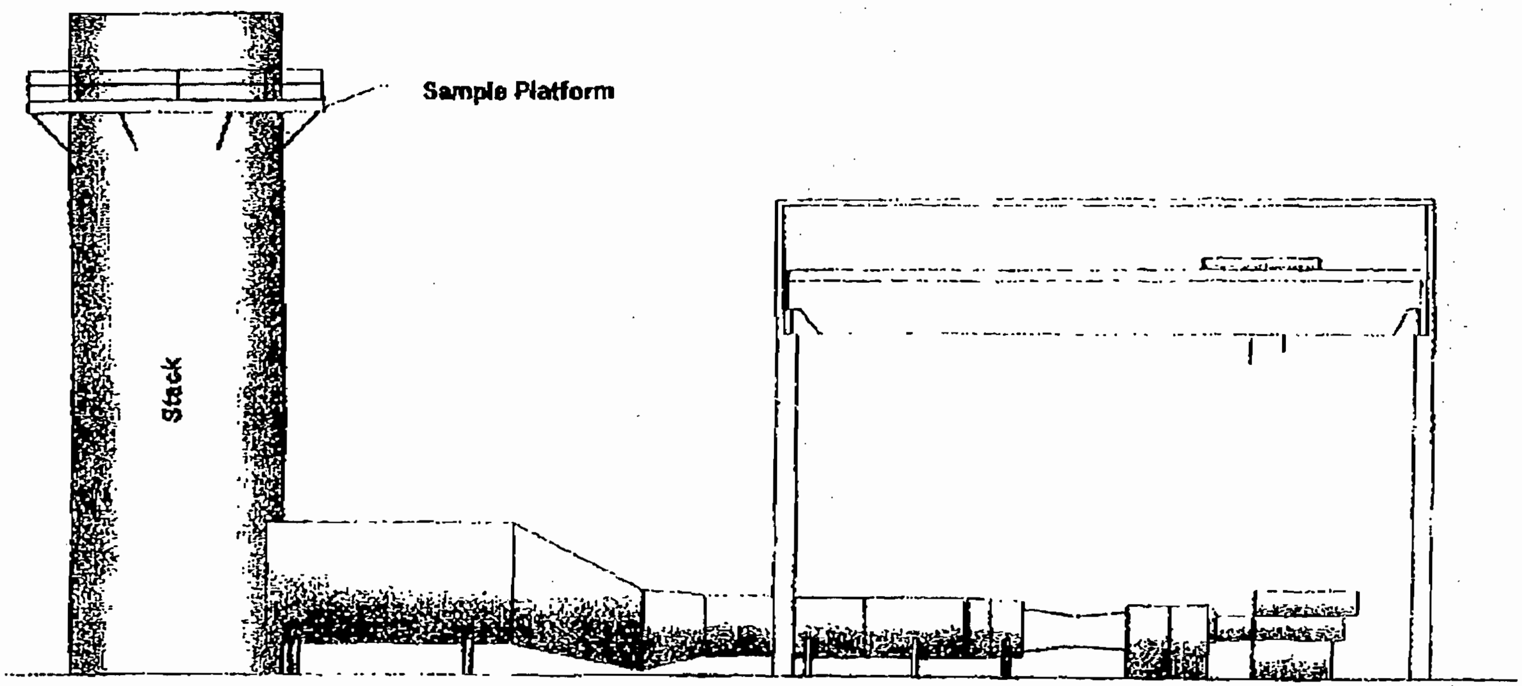
FUEL GAS CONTROL SYSTEM

The GCVs and SRV are actuated by hydraulic cylinders moving against spring loaded valve plugs. Three coil servo valves are driven by electrical signals from the control system to regulate the hydraulic fluid in the actuator cylinders. Redundant sensors in the form of Linear Variable Differential Transformers (LVDTs) mounted on each valve provide the control system with valve position feedback for closed loop position control. A functional explanation of each part or subsystem is contained in subsequent paragraphs. For more detail on the electro-hydraulic circuits see the SPEEDTRONIC System text, Gas Fuel system schematics, and Control Sequence Programs furnished to the site.

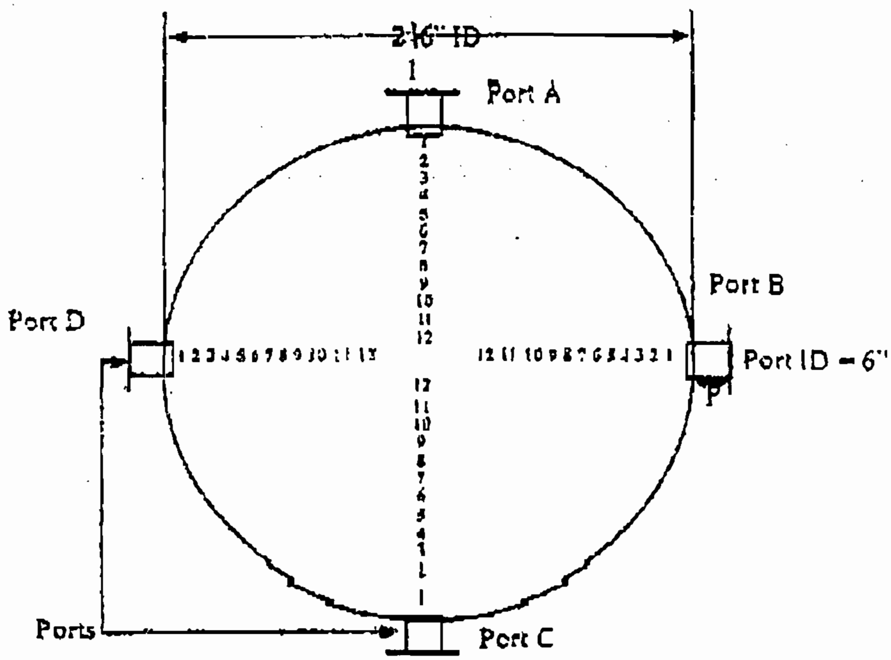
Gas Control Valves

The plugs in the GCVs are contoured to provide the proper flow area in relation to valve stroke. The combined position of the control valves is intended to be proportional to FSR. The GCVs use a skirted valve disc and venturi seat to obtain adequate pressure recovery. High pressure recovery occurs at valve pressure ratios substantially less than the critical pressure ratio. The result is that the flow through the GCVs is independent of the pressure drop across the valves and is a function of valve inlet pressure, P2, and valve area only. The control system's fuel command, FSR, is the percentage of maximum fuel flow required by the control system to maintain either speed, load, or another setpoint. FSR is broken down into two parts which make up the fuel split setpoint, FSR1 and FSR2. FSR1 is the percentage of maximum fuel flow required from the Liquid Fuel System and FSR2 is the percentage of maximum fuel flow required from the Gas Fuel System. FSR2 is also broken down into four parts, FSRPM1, FSRPM2, FSRPM3 and FSRQT. FSRPM1 is the percentage of FSR2 controlling the GCV1 gas fuel valve. FSRPM2 is the percentage of FSR2 to be directed to the GCV2 gas fuel valves, and so on. FSRPM1 is used as a reference to a servo amplifier, which drives the coils of GCV #1. FSRPM2 is used to drive the coils of GCV #2, and so on.

ATTACHMENT SH-EU1-J4
DESCRIPTION OF STACK SAMPLING FACILITIES



GENERAL ARRANGEMENT



Traverse Point	% of Diameter from near wall	Distance from Inner Wall (inches)
1	1.1	2.1
2	3.2	6.9
3	5.5	11.9
4	7.9	17.1
5	10.5	22.7
6	13.2	28.5
7	16.1	34.8
8	19.4	41.9
9	23.0	49.7
10	27.2	58.8
11	32.3	69.8
12	39.8	86.0

Figure - . Traverse point sampling CEMS

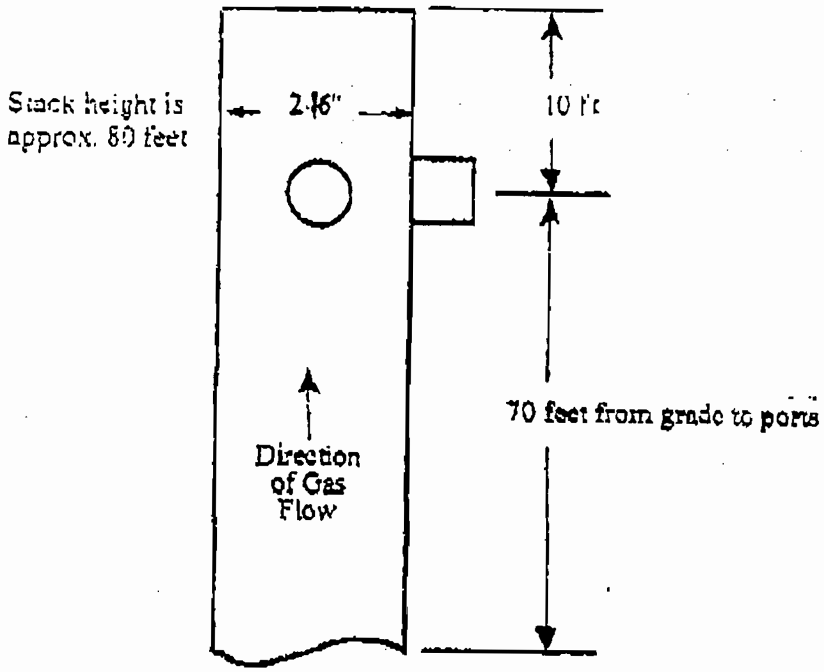


Figure - . Stack sample location.

ATTACHMENT SH-EU1-J6

PROCEDURES FOR STARTUP/SHUTDOWN

This attachment provides a general description of the startup and shutdown procedures as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

OPS-023 COMBUSTION TURBINE STARTUP

Shady Hills, FL
GE Contractual Services
Effective Date: Pending

Number: OPS-023
Attachment SH-EU1-J6a.doc

I. SCOPE

A. The purpose of this procedure is to provide safe means of Startup of the Gas Turbine Generators.

II. DEFINITIONS

A. None.

III. RESPONSIBILITIES

A. Facility Management

1. To revise this procedure when new safety measures and operating techniques or technologies become available.

B. Employee

1. To implement this operation by utilizing verbatim compliance of this procedure.
2. To use this procedure in parallel with all approved safety procedures.
3. To notify supervision when any unsafe or abnormal condition presents itself.

IV. GUIDELINES

A. Start required BOP Equipment

1. Start closed cooling water in accordance with OPS-031.
2. Start raw water for evap coolers in accordance with OPS-028.
3. Verify fuel systems are aligned in accordance with VLU's.
4. Start demin transfer pump in accordance with OPS-050.
5. Verify Compressed air system is online in accordance with OPS-037.
6. Verify gas heater is aligned and ready for operation in accordance with OPS-035.
7. Refer to OPS-044 for instructions on synchronizing.

B. Select "Main" display from the demand display.

1. HMI: Shutdown Status
   Off Cool down or ON Cool down
   Off

C. Select "Auto synchronize" ON

D. Select "Water Injection" ON

E. Select fuel to be used for start-up

F. Select "Auto" or "Remote" Depending on start location then "Execute".

1. "HMI: Startup Status
   Ready to Start
   Auto

G. Select "Start" and " Execute":

1. Unit Auxiliaries will be started lube oil flow will be established.
   a. HMI: Seq in progress
2. When permissives are satisfied (L4) will be satisfied.
   a. HMI: Startup Status
      Starting
      Auto; Start
3. When inot in cool down turning gear will engage, when unit realized approx. 6 rpm starting device will be energized and accelerate the unit.
   a. HMI: Startup Status Crank
4. When unit reaches 15% speed "14 HM" will appear on HMI at this time unit will purge for 5 minutes.
5. FSR will be set to firing valve. Ignition sequence is initiated.
   a. HMI: Startup Status/Firing
6. Flame established HMI; display will indicate flame in those combustors with flame detectors.
7. Select "Base Load"
8. FSR set back to warm-up valve.
   a. HMI: Startup Status/Warming up

NOTE

If flame goes out during the 60-second firing period, FSR will be reset to firing valve. At this time you may shut the unit down or attempt to fire again to fire again select CRANK on main display.

9. At the end of the warm up period, with flame established, FSR will increase.
   a. HMI: Start-up Status/Accelerating 50% speed "14HA" will be displayed on HMI.

10. Turbine will continue to accelerate, at 85-90% starting device will disengage and shutdown.

a. HMI: Startup control to speed control at approx 60% speed.

11. When turbine reaches operating speed "14HS" will be on HMI, field flashing is then terminated, if software switch (43S) is in off and remote is not selected on HMI.

a. HMI: Run Status
Full Speed No Load
Auto; Start

12. If 43S is in auto or remote on HMI; Automatic Sync is initiated.

a. HMI: Synchronizing

H. Normal Load Operation: Refer to OPS-043

NOTE:
Operator should monitor mode changes for proper DLN operation and indication of flame. Also monitor vibration screen for any extreme changes.

V. TRAINING

A. Complete Control Room Operator Qualifications.

VI. REFERENCES

A. GEK 107357 (GE Operations and Maintenance Manuel)
B. OPS-043
C. OPS-044

VII. APPENDIX

A. None

OPS-024 COMBUSTION TURBINE STARTUP

Shady Hills, FL
GE Contractual Services
Effective Date: Pending

Number: OPS-024
Attachment SH-EU1-J6b.doc

I. SCOPE

A. The purpose of this procedure is to provide safe means of shutting down the Gas Turbine Generators.

II. DEFINITIONS

A. None

III. RESPONSIBILITIES

A. Facility Management

1. To revise this procedure when new safety measures and operating techniques or technologies become available.

B. Employee

1. To implement this operation by utilizing verbatim compliance of this procedure.

2. To use this procedure in parallel with all approved safety procedures.

3. To notify supervision when any unsafe or abnormal condition presents itself.

IV. GUIDELINES

A. Select STOP on the <I> /HMI Main Display.

1. The unit will automatically unload, reduce speed, and chop fuel at part speed, and initation of cooldown sequence as unit coasts to a stop.

B. Immediately following shutdown verify unit is on turning gear to ensure minimum protection against rubs and unbalance on subsequent starting attempt.
G.E. recommends 48 hrs, prior to taking off cool down.

C. Shut down and isolate associated BOP equipment in accordance with procedures.

D. If this is the last unit to be shutdown refer to OPS-022 for supply systems to be shut down.

E. Upon completion of supply systems shutdown perform the following.

1. Walk unit down and inspect for leaks and any broken equipment.
2. Take a set of logs.
3. Verify unit is ready to start at HMI.
4. Clear any alarms, and investigate problems and correct.

V. TRAINING

A. Complete SR. Operations qualification.

VI. REFERENCES

A. GE Operations and Maintenance Manuals

ATTACHMENT SH-EU1-J7

OPERATION AND MAINTENANCE PLAN
FUEL GAS SYSTEM

This attachment provides a general description of operation and maintenance procedures as recommended by General Electric. Actual operation and maintenance plans will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU1-J7

OPERATION AND MAINTENANCE PLAN

FUEL GAS SYSTEM

GENERAL

The dry low NOx 2.6 (DLN-2.6) control system regulates the distribution of fuel delivered to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion chamber fuel nozzle assembly is calculated to maintain unit load and fuel split for optimal turbine emissions.

GAS FUEL SYSTEM

The DLN 2.6 Combustion system consists of six fuel nozzles per combustion can, each operating us a fully premixed combustor, five located radially, one located in the center. The center nozzle, identified as PM 1, (PreMix 1), two outer nozzles located adjacent to the crossfire tubes, identified as PM2, (PreMix 2), and the remaining three outer nozzles, identified as PM3, (PreMix 3). Another fuel passage, located in the airflow upstream of the premix nozzles, circumferentially around the combustion can, is identified as the quaternary fuel pegs, The fuel flow to the six fuel nozzles and quaternary pegs are controlled by four independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one, (PM1), gas control valve two (PM2), gas control valve three, (PM3), and gas control valve four, (Quat). The stop/ratio valve (SRV) is designed to maintain a predetermined pressure, (P2), at the inlet of the gas control valves. Gas control valves one through four, (GCVI-4), regulate the desired gas fuel flow delivered to the turbine in response to the command signal FSR, (Fuel Stroke Reference), from the SPEEDTRONIC panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. This flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software. The stop ratio valve and gas control valves are monitored for their ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to Warn the operator. If the condition persists for an extended amount of time, the turbine will be tripped and another alarm will annunciate the trip.

CHAMBER ARRANGEMENT

The 7F machine employs 14 combustors while the 9F employs 18 similar but slightly larger combustors. For each machine there are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent combustors. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi-nozzle cap assembly, liner assembly, and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion can, porting fuel to casing injection pegs located radially around the casing.

ATTACHMENT SH-EU1-J7

OPERATION AND MAINTENANCE PLAN
LIQUID FUEL SYSTEM

This attachment provides a general description of operation and maintenance procedures as recommended by General Electric. Actual operation and maintenance plans will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU1-J7

OPERATION AND MAINTENANCE PLAN

LIQUID FUEL SYSTEM

GENERAL

The liquid fuel (distillate oil) system filters, pressurizes, controls, and equally distributes fuel flow to the fourteen turbine combustion chambers. Flow is regulated by controlling the position of 3-way valve VC3-1. The entire liquid fuel system must be pressurized, with all valves in the open position, before starting the gas turbine. The liquid fuel system should be operated for a minimum of one half hour every week to prevent binding of the components. This is best achieved by operation of the turbine on liquid fuel for a minimum of one half hour per week with either 100% fuel oil or fuel gas mixed mode with fuel oil. The fuel system is comprised of the following major components:

1. Duplex low-pressure fuel filter FF1-l, -2 with transfer valve VM5-l and thermal pressure relief valves VR41-1, -2.
2. Fuel pump PF1-l with driving motor 88FP-1 and motor heater 23FP-l and discharge pressure relief valve VR4-1.
3. Fuel flow control valve VC3-1.
4. Fuel stop valve VS1-1.
5. Fuel flow divider FD1-1.
6. Nozzle pressure selector valve VH17-l.
7. Check valves VCKI-l through 14.
8. Fuel nozzle assemblies.

Except for the check valves and fuel nozzles all components are mounted in the off-base liquid, fuel/atomizing air module.

FUNCTIONAL DESCRIPTION

Duplex Low-Pressure Fuel Filter

Fuel oil forwarded to the liquid fuel module within specified pressure and temperature ranges enters the low pressure filter FF1-l or FFI-2 via transfer valve VM5-1 prior to entering the fuel pumps. The low-pressure filter consists of multiple five-micron synthetic elements with oversize contamination capacity. These elements retain contaminants, which could damage downstream components. The filter vessels are protected from thermal overpressure by relief valves

VR41-1, -2. Differential pressure switch 63LF-5 gives a signal when the pressure drop across the filter reaches 15 psid (103 kPad). The ditty filter should then be serviced by replacing the dirty elements with clean ones.

Fuel Pump

Fuel pump PFI-1 is of the axial flow, positive displacement, rotary, screw type with one power rotor (driven screw) and two intermeshing idler rotors. The single ball bearing positions the power rotor for proper operation of the mechanical seal. The bearing is permanently "'grease packed and external to the pumped fuel. The motor driven fuel pump 88FP/PFI-1 is rated at one hundred percent capacity of the maximum turbine fuel requirement. The pump motor is equipped with an integral heater 23FP-l. The pump is protected from insufficient suction pressure by permissive-to-start pressure switch 63FL.2. During normal operation this switch functions as a low-pressure alarm. The fuel system is protected from excessive pressure by pump discharge relief valve VR4-1 that relieves pressure back to filter inlet.

Fuel Flow Control Valve

Pump discharge flow is modulated by the servocontrolled three-way control valve assembly VC3-1. Components of this assembly include the valve body, electrohydraulic servovalve 65FP-1, hydraulic oil filter FH3-1 and the cylinder. The valve controls the flow to the turbine by throttling the main port while opening the bypass port, returning the bypass flow to pump suction.

Liquid Fuel Stop Valve

Hydraulically operated three-way fuel oil stop valve VS1-1 shuts off the supply of fuel to the turbine during normal or emergency shutdowns. During normal turbine operation, the valve is held open (bypass closed) by high-pressure hydraulic oil that passes through a hydraulic trip relay (dump) valve VH4-1. This dump valve, located between the hydraulic supply and the stop valve hydraulic cylinder, is hydraulically operated by trip oil acting through solenoid valve 20FL-l. During a normal shutdown or emergency trip, low trip oil pressure will cause valve VH4-1 to shift position, dumping high-pressure hydraulic oil from the stop valve actuating cylinder, allowing the stop valve spring to close the valve. During an electrical trip, solenoid valve 20FL-l causes the dump valve to shift with the same results as above. The stop valve will be fully closed within 0.5 second of the trip signal. Limit switch 33FL-l signals stop valve closed position.

Flow Divider

Flow divider FD1-1 equally distributes filtered fuel to the 14 combustors. It is a continuous flow, free wheeling device consisting of fourteen gear pump elements in a circular or linear arrangement having a common inlet with a single timing gear or shaft. This timing (sun) gear or shaft maintains the speed of each flow element synchronous with all the other elements.

The speed of each flow divider gear element is directly proportional to the total flow through the flow divider. Magnetic pickup assemblies 77FD-l, -2 and -3, fitted to the flow divider, produce a flow feedback signal at a frequency proportional to the fuel delivered to thc combustion chambers. This signal is fed to the SPEEDTRONICE control panel where it is used in the fuel control system.

Pressure Selector Valve

An eighteen position pressure selector valve VH17-l allows monitoring of individually selected line pressures on a local gauge. These include: anyone of the fourteen combustor fuel lines; pump discharge pressure; and flow divider inlet pressure.

Check Valves

Check valves VCKI-l through 14 isolate the fuel nozzles during shutdown periods to prevent line drainage and flow communication between combustors.

ATTACHMENT SH-EU1-J14
COMPLIANCE ASSURANCE MONITORING PLAN

ATTACHMENT SH-EU1-J14

COMPLIANCE ASSURANCE MONITORING PLAN

The only control device for the CT is water injection for NOx control. Continuous Emission Monitors (CEMS) monitor NOx, therefore the Compliance Assurance Monitoring Plan is not applicable.

ATTACHMENT SH-EU1-J15
ACID RAIN PART APPLICATION

Golder Associates Inc.

5100 West Lemon Street, Suite 114
Tampa, FL USA 33609
Telephone (813) 287-1717
Fax (813) 287-1716

Golder Associates

November 12, 2001

Project No.013-9517

Mr. Bob Miller
US EPA Clean Air Markets
Mail Code 6204J
501 3rd Street, NW
Washington, DC 20001

RE: Acid Rain Permit
Shady Hills Power Company, L.L.C.
Shady Hills Generating Station
Pasco County, Florida

Dear Mr. Miller:

Enclosed is notification of a change in the designated representative and alternate designated representative for the above referenced project. Please find The Certificate of Representation [EPA Form 7610-1(rev.4-98)], which identifies Mr. James M. Packer, Director of Operations and Mr. John E. Dorsett, Vice President of Business Development/Operations, Shady Hills Power Company, L.L.C. as the designated representative and alternate designated representative, respectively.

Shady Hills Power Company, L.L.C. and Golder Associates Inc. appreciate your assistance in processing the above referenced information. If you have any questions or need additional information, please contact me at (813) 287-1717.

Very truly yours,

GOLDER ASSOCIATES INC.

Manitia Moultrie

Manitia Moultrie
Senior Project Manager

MM/AT/nd

Enclosures

cc: Mr. Scott Sheplak, Florida Department of Environmental Protection
Mr. Jimmy Packer, Mirant Corporation
Mr. Chuck Jordan, Mirant Corporation
Mr. Glenn Keeling, Mirant Corporation

H:\GolderVol1\PROJECTS\2001proj\013-9517 Mirant - Shady Hills Compliance\0100 - Project Management\REP TRANSFER 10-01\transfer of authorized rep-Miller.doc

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Certificate of Representation

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
Shady Hills Generating Station	FL	55414

STEP 2
Enter requested information for the designated representative.

Name: James M. Packer, Shady Hills Power Company, L.L.C.

Address: 1155 Perimeter Center West
Atlanta, Georgia 30338-5416

Phone Number	Fax Number
(678) 579-7962	(678) 579-7358

E-mail address (if available): jimmy.packer@mirant.com

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

Name: John E. Dorsett

Phone Number	Fax Number
(678) 579-7349	(678) 579-7358

E-mail address (if available): eddie.dorsett@mirant.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 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.

Shady Hills Generating Station
Plant Name (from Step 1)

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.

James M. Packer Signature (designated representative)	11-07-01 Date
[illegible] Signature (alternate designated representative)	11-08-01 Date

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.

Shady Hills Power Company, L.L.C. Name					☒ Owner ☐ Operator	
CT1 ID#	CT2 ID#	CT3 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#

Name					☐ Owner ☐ Operator	
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

EL PASO
MERCHANT ENERGY

November 21, 2000

Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399
MS 5505

Attention: Mr. Scott Sheplak, P.E.

RE: Acid Rain Program, Phase II Permit Application
Shady Hills Power Company, L.L.C. – Shady Hills Generating Station

Dear Mr. Sheplak:

Please find attached a Phase II Permit Application for the Shady Hills Generating Station located in Pasco County, Florida that is owned and operated by the Shady Hills Power Company, L.L.C. With one exception, this certificate is submitted in accordance with the provisions of Title 40, Parts 72.30 and 72.31 of the Code of Federal Regulations applicable to facilities regulated by the Acid Rain Program. This exception is in regard to the date of submission described in the regulation as the later of 24 months prior to January 1, 2000 or 24 months prior to the unit commencing operation. Due to the short period of time before the anticipated start of operation for the facility (January 2002), Shady Hills Power Company, L.L.C. was unable to meet this deadline.

Also, please find attached a copy of the Certificate of Representation form as the original was sent to the US EPA.

If you have any questions concerning the attached information, please call me at the phone number provided.

Sincerely,
Shady Hills Power Company, L.L.C.

John J. O'Rourke
V. P. and Managing Director
Venture Management

Enclosures

COPY

El Paso Merchant Energy Company P. O. Box 2511 Houston, Texas 77252-2511 1001 Louisiana Street Houston, Texas 77002

Phase II Permit Application

Page 1

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

This submission is: ■ New ☐ Revised

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

Plant Name Shady Hills Generating Station	State FL	ORIS Code 55414

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	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
GT 101	Yes		Jan 29, 2002	April 30, 2002
GT 201	Yes		Jan 29, 2002	April , 2002
GT 301	Yes		Mar 1, 2002	Jun 1, 2002

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.

Shady Hills Generating Station

Plant Name (from Step 1)

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Shady Hills Generating Station

Plant Name (from Step 1)

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 Mr. John O'Rourke	
Signature J O'Rourke	Date 11/27/00

STEP 5 (optional)
Enter the source AIRS
FINDS identification

AIRS	
FINDS	

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

GE Frame 7FA Combustion Turbine

4. Emissions Unit Identification Number: [ ] No ID
ID: **002** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**April 2002**	**49**	[X]

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

This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment SH-EU2-A9.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_x combustion - Natural gas firing** **Water injection - Distillate oil firing**	
2. Control Device or Method Code(s): **25, 28**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** 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:			1,858	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		days/week
		weeks/year	5,000	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum heat input at 100% load and 32°F oil firing (LHV).
Maximum for gas firing is 1,670 MMBtu/hr at 100% load and 32°F (LHV).
The CTs will operate no more than an average of 3,390 hrs/CT/yr.
No single CT will operate > 5,000 hrs per year.
See Attachment SH-EU2-B6 for performance specifications and manufacturer guarantees.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment SH-EU2-D	

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? **CT2**	2. Emission Point Type Code: **1**

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

Exhausts through a single stack.

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

5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,645,000**	10. Water Vapor: **8.6** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **347.0** North (km): **3139.0**

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

Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.

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):

   Distillate (No. 2) Fuel Oil

2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **13.7**	5. Maximum Annual Rate: **13,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**

10. Segment Comment (limit to 200 characters):

    Million Btu per SCC Unit = 131.8 (rounded to 132). Based on 7.1 lb/gal; LHV of 18,560 Btu/lb, ISO conditions, 1,000 hrs/yr operation. The amount of fuel oil burned (BTU's) will not exceed the amount of natural gas burned (BTU's) per year.

Segment Description and Rate: Segment 2 of 2

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

   Natural Gas

2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.70**	5. Maximum Annual Rate: **5,752**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**

10. Segment Comment (limit to 200 characters):

    Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025	028	EL
CO			EL
VOC			EL
PM_{10}			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if < 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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 **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load;TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 grain/100 cf - 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **3-Hour Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 1998; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See PSD Air Construction Permit Application; Section 2.0; Appendix A.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions

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: **9 ppmvd**
4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters):

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

   Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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**	4. Equivalent Allowable Emissions: **74.4** lb/hour **35.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: 16.7 lb/hour 11.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See PSD Air Construction Permit Application; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions	

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: 7 ppmvw	4. Equivalent Allowable Emissions: 16.7 lb/hour 8.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10 – CO Test	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.	

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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 – CO Test**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17; if <400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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 **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other **(BACT)**
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **VE Test serves as a surrogate for PM/PM_{10} compliance testing.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Horiba** Model Number: **ENDA-E4220LS**	Serial Number: **11527**
5. Installation Date: **01 Nov 2001**	6. Performance Specification Test Date: **15 Feb 2002**
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **2 hrs/24 hrs** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-210.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Horiba** Model Number: **ENDA-E4220LS** Serial Number: **11527**	
5. Installation Date: **01 Nov 2001**	6. Performance Specification Test Date: **15 Feb 2002**
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: Water/Fuel Ratio. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: SH-EU2-J1 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: SH-EU2-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: SH-EU2-J3 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: SH-EU2-J4 [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [X] Previously submitted, Date: 3/29/02 [ ] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: SH-EU2-J6 [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [X] Attached, Document ID: SH-EU2-J7 [ ] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: ________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

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

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

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

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

    [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: SH-EU2-J15

    [ ] 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

ATTACHMENT SH-EU2-A9

EMISSIONS UNIT COMMENT

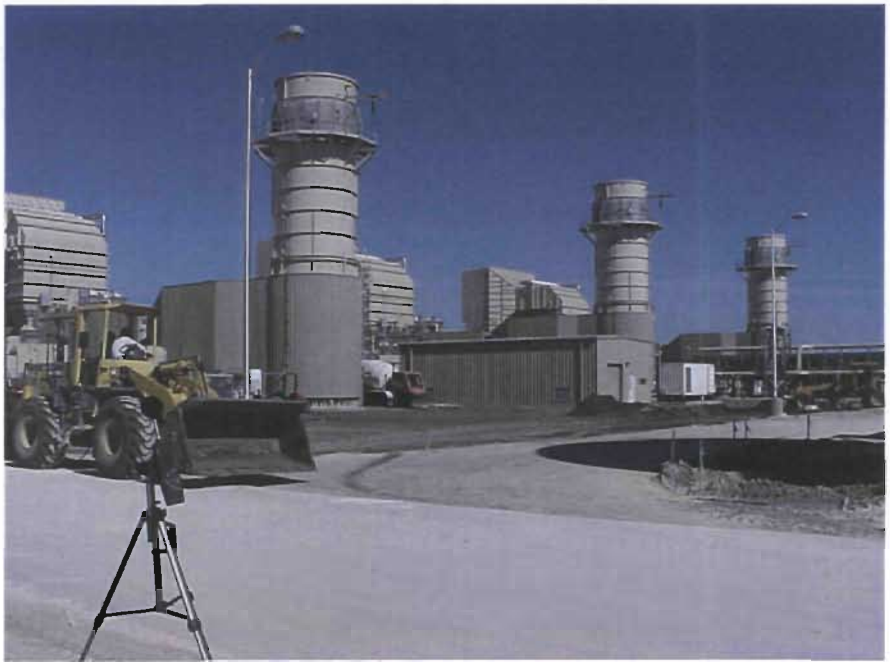


Photo 1. Diagonal View - Combustion Turbine

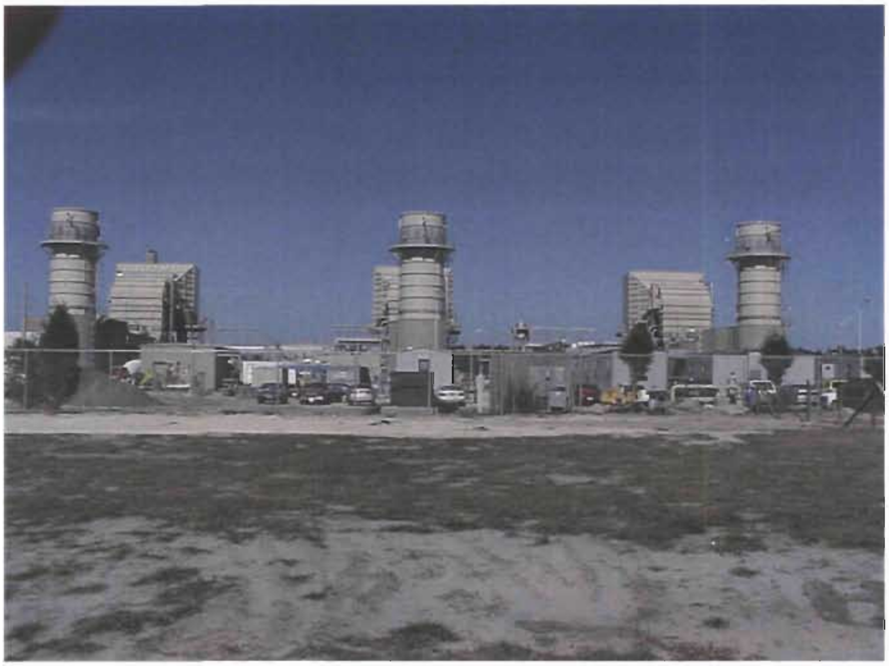


Photo 2. Front View - Combustion Turbine

Attachment SH-EU2-A9
Shady Hills Generating Station Photos

Source: Golder, 2002.

Golder Associates

ATTACHMENT SH-EU2-B6

OPERATING CAPACITY/SCHEDULE COMMENT

2. Performance Guarantees

2.1 Guaranteed Performance

Operating Point	Fuel	Output (kW)	Heat Rate (Btu/kWh, LHV)
Baseload, 95°F, 64% RH	Natural Gas	154,100	9,680
Baseload, 95°F, 64% RH	Distillate Oil	165,500	10,150
Heat Rate = Fuel Consumption (Btu/h, LHV) / Output (kW)			

2.1.1 Basis For Equipment Performance

The performance guarantees listed above are based on the scope of equipment supply as defined in this proposal and as stated for the following operating conditions and cycle parameters:

a. The natural gas fuel and distillate fuel oil are in compliance with Seller's Gas Fuel Specification GEI-41040F and Liquid Fuel Specification 41047H respectively and supplementary Fuel, Air and Steam Purity Requirements as defined in this proposal.

b. Natural Gas Fuel Heating Value = 20,773 Btu/lb (LHV)

c. Distillate Fuel Oil Heating Value = 18,300 Btu/lb (LHV)

d. Site Elevation = 50 ft

e. Site Pressure = 14.67 psia.

f. Inlet Loss = 4.0 in Water

g. Exhaust Loss = 5.5 in Water

h. Evaporative Cooler = On, with 85% effectiveness

i. Fuel Gas Supply Temperature = 80°F (@ GT stop valve)

j. Fuel Gas Supply Pressure = 450 psig - 475 psig (@ GT stop valve)

k. Gas turbines are operating at steady state baseload.

l. Tests to demonstrate guaranteed performance shall be conducted in accordance with the ASME Performance Test Procedure as defined in this proposal (GEK-41067D).

m. Generator power factor for baseload operation = .85 lagging.

n. Performance is measured at the generator terminals and includes allowances for excitation power and the shaft-driven equipment normally supplied.

o. Station services for GE supplied auxiliaries are not included in the guaranteed performance.

p. The equipment is in a new and clean condition (less than 100 fire hours of operation).

q. Performance curves such as ambient effects curves and generator efficiency curves will be provided after contract award. These curves are to be used during the site performance test to correct performance readings back to the site conditions at which the performance guarantees were provided. Where available, typical correction curves have been supplied.

r. Natural gas performance is based on operation with a dry low NOx combustion system without gas turbine diluent injection for NOx control.

s. Distillate fuel oil performance is based on diluent injection flow rate of 93,890 lb/hr. The actual amount of diluent injection as determined during the field compliance test may be different, which will have an effect on the output and heat rate.

t. Compressor air extraction from gas turbine = 0.

u. Natural Gas Analysis (%vol) =

Nitrogen	0.2441	Propane	0.8050	Pentane	0.0329
CO2	0.9672	I-Butane	0.1956	Hexane	0.0855
Methane	94.7081	Butane	0.1754		
Ethane	2.7296	I-Pentane	0.0565		

v. A nominal distillate oil analysis was assumed for the guarantees.

2.2 Emissions Guarantees

Exhaust gas emissions shall not exceed the following concentrations during steady-state operation from baseload down to 50% CT load over the ambient temperature range from 20°F to 100°F for each of the gas turbines:

	Natural Gas	Distillate Oil
NOx, ppmvd Ref. 15% O_2, ISO	9	42
CO, ppmvd	12	20
VOC, ppmvw	1.4	3.5
Particulates (TSP - front half only), lb/hr	9	17
Opacity	10%	20%

2.2.1 Basis For Emissions Guarantees

a. The natural gas fuel and distillate fuel oil are in compliance with Seller's Gas Fuel Specification GEI-41040F and Liquid Fuel Specification 41047H respectively and supplementary Fuel, Air and Steam Purity Requirements as defined in this proposal.

b. Testing and system adjustments are conducted in accordance with GEK-28172F, Standard Field Testing Procedure for Emissions Compliance included in the Reference Specifications/Documents Tab of this proposal.

c. Ambient air pressure = 14.67 psia

d. Emissions are per gas turbine on a one hour average basis.

e. Fuel bound nitrogen = 0% on NG; maximum of 0.015% (by wt) on distillate fuel oil

f. Fuel ash content = 0%

g. Sulfur emissions are a function of the sulfur present in the incoming air and fuel flows. Since the gas turbine(s) have no influence on the sulfur emissions when no sulfur is present in the fuel, sulfur based emissions are not guaranteed

h. GE reserves the right to determine the emission rates on a net basis wherein emissions at the gas turbine inlet are subtracted from the measured exhaust emission rate if required to demonstrate guarantee rate.

ATTACHMENT SH-EU2-D

APPLICABLE REQUIREMENTS

ATTACHMENT SH-EU2-D

Applicable Requirements Listing

EMISSION UNIT ID: EU2

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	NSPS Subpart GG
62-204.800(7)(c) (State Only)	NSPS authority
62-204.800(7)(d)(State Only)	NSPS General Provisions
62-204.800(12) (State Only)	Acid Rain Program
62-204.800(13) (State Only)	Allowances
62-204.800(14) (State Only)	Acid Rain Program Monitoring
62-204.800(16) (State Only)	Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	Circumvention; EUs with control device
62-210.700(1)	Excess Emissions;
62-210.700(4)	Excess Emissions; poor maintenance
62-210.700(6)	Excess Emissions; notification

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320	All Acid Rain Units (Application Shield)
62-214.330(1)(a)	Compliance Options (if 214.430)
62-214.340	Exemptions (retired units)
62-214.350(2);(3);(5);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)	All Units (Operating Rate)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)	All Units (Applicable Test Procedures)
62-297.310(5)	All Units (Determination of Process Variables)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)
62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels

62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.	Annual Test
62-297.310(7)(a)5.	PM exemption if <400 hrs/yr
62-297.310(7)(a)8.	VE Compliance Test if > 400 hrs/yr
62-297.310(7)(a)9.	FDEP Notification - 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Requirements
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(d)	Performance Test Notification
40 CFR 60.8(e)	Provide Stack Sampling Facilities
40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention
40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)

Acid Rain-Permits:

40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iv)	SO_2 Allowances-Phase II Units
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS

40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID;unit/system ID
40 CFR 72.33(c)	Dispatch System ID;ID requirements
40 CFR 72.33(d)	Dispatch System ID;ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	Compliance Dates;
40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(c)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)

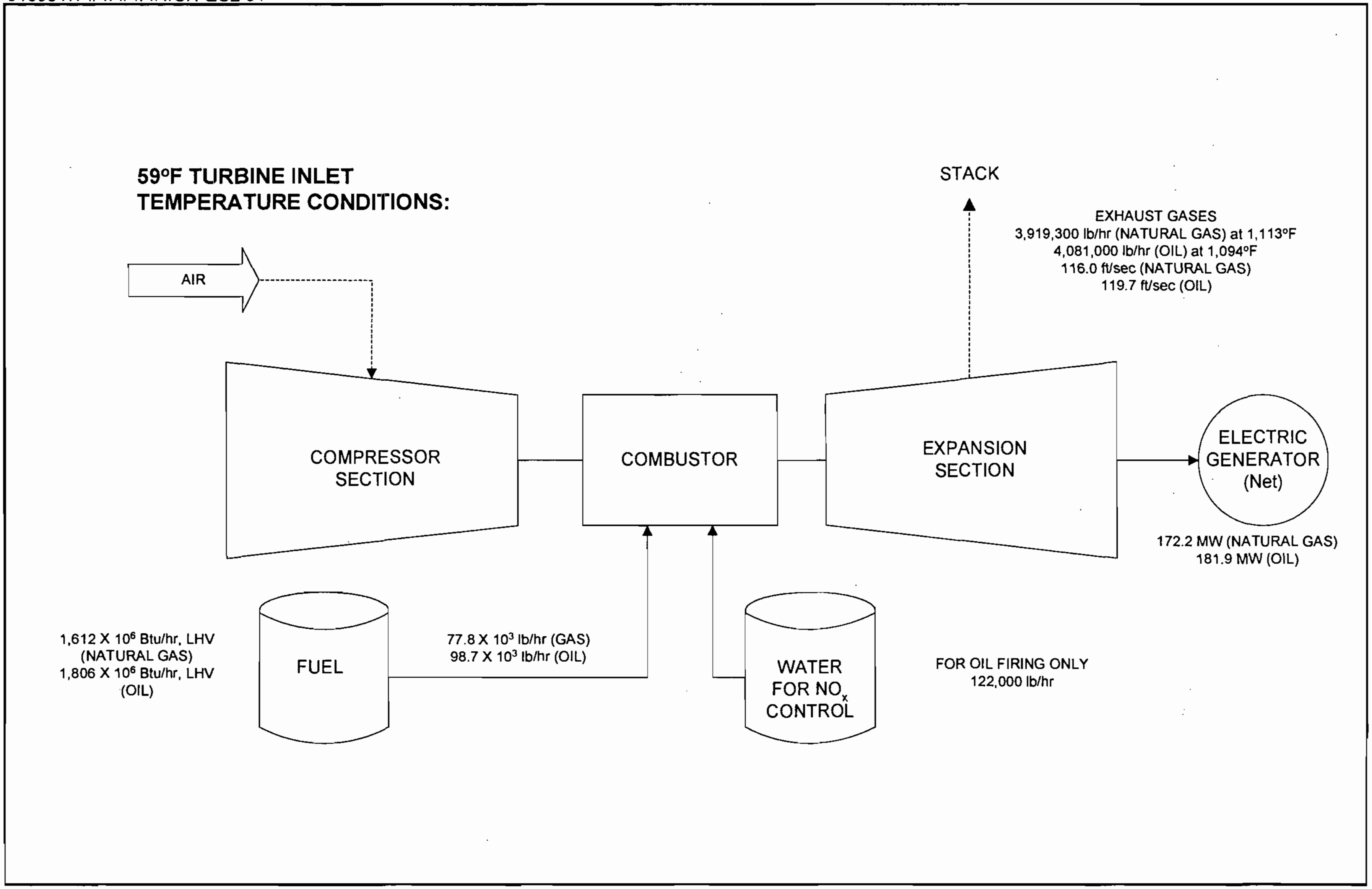
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; CO_2
40 CFR 75.30(d)	General Missing Data Procedures; SO_2
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.53	Monitoring Plan; revisions
40 CFR 75.57(a)	Recordkeeping Requirements for Affected Sources
40 CFR 75.57(b)	Operating Parameter Record Provisions
40 CFR 75.57(d)	NO_x Emission Record Provisions
40 CFR 75.57(e)	CO_2 Emission Record Provisions
40 CFR 75.57(h)	Missing Data Records
40 CFR 75.58(c)	Specific SO_2 Emission Record Provisions
40 CFR 75.58(e)	Specific SO_2 Emission Record Provisions
40 CFR 75.59	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.64(f)	Method of Submission
40 CFR 75.64(g)	Submission Requirements
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A	Specifications and Test Procedures
Appendix B	QA/QC Procedures
Appendix C.	Missing Data Estimation Procedures
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures

Acid Rain Program-Excess Emissions:

40 CFR 77.3	Offset Plans
40 CFR 77.5(b)	Deductions of Allowances
40 CFR 77.6	Excess Emissions Penalties (SO_2)

ATTACHMENT SH-EU2-J1

PROCESS FLOW DIAGRAM



Attachment SH-EU2-J1
Simplified Flow Diagram of GE Frame 7FA
Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: SH-EU2-J1
Date: 3/29/02

Golder Associates

ATTACHMENT SH-EU2-J2

FUEL SPECIFICATION

NO. 2 FUEL OIL

Table 2 - Liquid Fuel Specifications							
				True Distillates (b)		**Ash-Bearing Fuels (b)**	
Applicability	**Property**	**Point of Applicability (a)**	**ASTM Test Method (c)**	**Light**	**Heavy**	**Crudes and Blended Residual Fuels**	**Heavier Residual Fuels**
3.1 Gas Turbine Requirements	Kin. Viscosity, cSt, 100°F (37.8°C), min	Delivery	D445	.5(d)	1.8	1.8	1.8
	Kin. Viscosity, cSt, 100°F (37.8°C), max (e)	Delivery	D445	5.8	30	160	900
	Kin. Viscosity, cSt, 210°F (98.9°C), max (e)	Delivery	D445	—	4	13	30
	Specific Gravity, 60°F (15.6°C), max	Delivery	D1298	Report	Report	.96	.96(f)
	Flash Point, °F(°C), min (g)	Delivery	D93	Report	Report	Report	Report
	Distillation Temp. 90% Point, °F(°C), max	Delivery	D86	650(338)	Report	—	—
	Pour Point, °F(°), max	Delivery	D97	0 (-18) or 20 (7) below min. ambient	Report	Report	Report
	Hydrogen, Wt %, min (k)	Delivery	(i)	Report	Report	Report	Report
	Carbon Residue, Wt. % (10% Bottoms) max Direct Pressure Atomization	Delivery	D524	.25	—	—	—
	Carbon Residue, Wt. % (100% Sample) max Air Atomization, Low Pressure	Delivery	D524	1.0	1.0	1.0	—
	Carbon Residue, Wt. % (100% Sample), Air Atomization, High Pressure	Delivery	D524	—	—	Report	Report
	Ash, ppm, max	Combustor	D482	50	50	Report	Report
	Trace Metal Contaminants, ppm, max (h)	Combustor	(i)				
	Sodium plus Potassium			1	1	1	1
	Lead			1	1	1	1
	Vanadium (untreated)			.5	.5	.5	.5
	Vanadium (treated 3/1 wt. ratio Mg/V)			—	—	100	500
	Calcium			2	2	10	10
	Other Trace Metals above 5 ppm			Report	Report	Report	Report
The specifications below apply only when specific environmental codes exist							
3.2 Environmental Code Related Requirements	Sulfur, Wt. %, max	Delivery	D129	Compliance to any applicable codes.			
	Nitrogen, Wt. %, max	Delivery	(i)	Fuel-bound nitrogen may be limited to meet any applicable codes on total NO_x emission.			
	Hydrogen, Wt. %, min.	Delivery	(i)	Minimum hydrogen level may be necessary to meet any applicable stack plume opacity limits (k).			
	Ash plus Vanadium, ppm, max.	Delivery	(i)	Ash plus vanadium content of ash-bearing fuels may be limited to meet applicable stack particulate emission codes (l).			

NOTES TO TABLE 2

a. The fuel properties specified refer to the fuel at different points in the overall system:
Delivery — Fuel as delivered to the turbine site.
Fuel Skid — Fuel at inlet of fuel skid at turbine.
Combustor — Fuel at turbine combustors.

b. Typical fuels within each general type are discussed in Appendix A.

c. ASTM Book of Standards, Parts 23 and 24.

d. In the viscosity range of 0.5 cSt to 1.8 cSt, special fuel pumping equipment may be required.

e. The maximum allowable viscosity at the fuel nozzle is 20 cSt for high pressure air atomization and 10 cSt for low pressure air and direct pressure atomization. The fuel may have to be preheated to reach this viscosity, but in no instance shall it be heated above 275°F (135°C). (This maximum fuel temperature of 275°F is allowed only with residual fuels.) The viscosity of the fuel at initial light-off must be at or below 10 cSt.

f. A specific gravity of 0.96 is based on average fuel desalting capability with standard washing systems. Fuels with specific gravities greater than 0.96 may be desalted to the required minimum sodium plus potassium limits by using higher capability desalting equipment (with higher attendant cost) or by increasing the gravity difference between the fuel and wash water by blending the fuel with a compatible distillate.

g. The fuel must comply to all applicable codes for flash point.

h. A total ash less than 3 ppm is acceptable in place of trace metal analysis.

i. No standard reference tests exist; methods used should be mutually acceptable to General Electric and the user.

j. Water content of crude oils should be reduced to the lowest level practical consistent with capability of available fuel treatment equipment, to minimize the chance of corrosion of fuel system components. In no case shall the water content exceed 1.0 vol. %.

k. A minimum hydrogen content is set both to control flame radiation in the combustor and to limit smoke emissions, where the latter is required by local codes. The limits are 12.0% minimum for true distillates and 11.0% for Ash-bearing fuels (11.3% where the carbon residue exceeds 3.5%). In each case it is assumed that the proper combustor and fuel atomization system are used.

Where the hydrogen content of the fuel is below these limits, General Electric should be consulted for appropriate action.

l. Local codes on total stack particulate emissions may set an upper limit on the sum of the ash (non-filterable) in the original fuel plus the vanadium content. The vanadium together with the required magnesium inhibitor may be a major contributor to total stack particulate emissions. In estimating these emissions for comparison with the code, all of he following sources may have to be considered: vanadium, additives, fuel ash and total sulfur in the fuel; non-combustible particulates in the inlet air; solids from any injected steam or water; and particles from in-

ATTACHMENT SH-EU2-J2

FUEL SPECIFICATION

NATURAL GAS

<table>
<tr><th colspan="6">TABLE 2
GAS FUEL SPECIFICATION</th></tr>
<tr><th>FUEL PROPERTIES</th><th colspan="2">MAX</th><th colspan="2">MIN</th><th>NOTES</th></tr>
<tr><td>Lower Heating Value, Btu/lb</td><td colspan="2">None</td><td colspan="2">100 – 300</td><td>See note 3</td></tr>
<tr><td>Modified Wobbe Index Range</td><td colspan="2">+5%</td><td colspan="2">–5%</td><td>See Notes 4,5</td></tr>
<tr><td>Superheat, °F</td><td colspan="2">–</td><td colspan="2">50</td><td>See Note 6</td></tr>
<tr><td>Flammability</td><td colspan="2">See Note 7</td><td colspan="2">>2.2:1</td><td>Rich to lean fuel to air ratio, volume basis
See Note 8</td></tr>
<tr><td>Gas Constituent Limits, % by volume:</td><td colspan="2"></td><td colspan="2"></td><td></td></tr>
<tr><td>Methane</td><td colspan="2">100</td><td colspan="2">85</td><td>% of reactant species</td></tr>
<tr><td>Ethane</td><td colspan="2">15</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Propane</td><td colspan="2">15</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Butane + Paraffine (C4+)</td><td colspan="2">5</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Hydrogen</td><td colspan="2">0</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Carbon Monoxide</td><td colspan="2">15</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Oxygen</td><td colspan="2">10</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Carbon Dioxode</td><td colspan="2">15</td><td colspan="2">0</td><td>% total (reactants + inerts)</td></tr>
<tr><td>Nitrogen</td><td colspan="2">30</td><td colspan="2">0</td><td>% total (reactants + inerts)</td></tr>
<tr><td>Sulfur</td><td colspan="2">–</td><td colspan="2">–</td><td>See Note 9</td></tr>
<tr><td>Total Inerts (N_2 + CO_2+AR)</td><td colspan="2">30</td><td colspan="2">0</td><td></td></tr>
<tr><td>Aromatics (Benzene, Toluene etc.)</td><td colspan="2">Report</td><td colspan="2">0</td><td>See Note 10</td></tr>
<tr><td>Gas Fuel Supply Pressure</td><td colspan="2"></td><td colspan="2"></td><td>See Note 11</td></tr>
<tr><th>CONTAMINANTS
(See Notes 12,13)</th><th colspan="4">FUEL LIMITS
ppmw (See Note 14)</th><th>NOTES</th></tr>
<tr><td>Particulate</td><td>MS3000
MS5000</td><td>B/E Class</td><td>F Class</td><td>H Class</td><td>See Note 15</td></tr>
<tr><td>Total
Above 10 Microns</td><td>35
0.4</td><td>32
0.3</td><td>23
0.2</td><td>23
0.2</td><td></td></tr>
<tr><td>Trace Metals
Sodium plus potassium</td><td colspan="4">0.8</td><td>See Note 16</td></tr>
<tr><td>Liquids</td><td colspan="4">0</td><td>No Liquids allowed, see superheat requirements and Note 17</td></tr>
</table>

Notes:

1. All fuel properties must meet the requirements from ignition to base load unless otherwise stated.

2. Values and limits apply at the inlet of the gas fuel control module.

3. Heating value ranges shown are provided as guidelines. Specific fuel analysis must be furnished to GE for proper analysis. (Reference Section III-A)

4. See section III-B. for definition of Modified Wobbe Index Range.

ATTACHMENT SH-EU2-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

This attachment provides a general description of the water injection system's operation as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU2-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

GENERAL

The water injection system provides water to the combustion system of the gas turbine to limit the levels of nitrogen oxides (NOX) in the turbine exhaust. This limitation is required by strict local and federal regulations. The water injection system schedules water flow to the turbine as a function of total fuel flow, relative humidity, and ambient temperature. The required water/fuel ratio is established through field compliance testing of the individual turbine. A final control schedule based on these tests is programmed in the SPEEDTRONICE control, which then regulates the system. The water injection system consists of both on-base components and an off-base water injection skid. This skid is a factory assembled and enclosed package. It receives water from the customer's treatment facility, and delivers filtered water at the pressure and flow rate required to meet the applicable emissions requirement at that operating condition. The filtered water is introduced to the turbine combustion system through a water supply manifold. The manifold supplies water to each of the 14 combustors on the gas turbine. The manifold inlet connection is located on the turbine base. The water is injected through identical nozzles in each of the combustors. The following is a brief functional description of the system as well as a control and monitoring description. More detailed information on individual items is given in the manufacturer's literature (Equipment Publications).

FUNCTIONAL DESCRIPTION

The water injection system supplies treated and filtered water at the required flow rate and pressure to the combustion system of the gas turbine. Water enters the skid and passes through a strainer (FW1-2), which protects the system components from damage by foreign objects. A pressure switch (63WN-1) senses pressure upstream of the Pump. The SPEEDTRONICE control system will trip the pump motor if the pressure sensed by this switch is too low. This protects the pump from damage due to cavitation. An electric motor (88WN-1) drives the centrifugal water injection pump (PW1-1). The speed of the electric motor is controlled by a Variable Frequency Drive unit or VFD (97WN-1). The VFD modulates the frequency of the AC power supplied to the motor (88WN-1). By varying the frequency of the AC power, the pump speed can be precisely controlled. By varying the pump speed, the pump discharge pressure, and hence the discharge flow rate are controlled. The VFD controls the pump speed in response to a 4-20 mA

demand signal from the SPEEDTRONICE. A 0-10 V speed feedback signal (96WN-4) from the VFD is fed back to the SPEEDTRONICE□ for monitoring and fault detection purposes.

A discharge pressure transmitter (96WP-1) is located downstream of the pump. The signal from this transmitter is fed back to the SPEEDTRONICE □ for monitoring and fault detection. The flow then passes through a high pressure filter assembly (FW1-1). The filter elements are contained in a high pressure filter housing, with a vent and drain. A differential pressure gauge indicates the pressure drop across the filter. A differential pressure switch (63WN-3) also senses the differential pressure across the filter, and signals an alarm in the SPEEDTRONICE control if the pressure differential exceeds the pressure specified in the device summary. Downstream of the filter, the flow is split into a main line to the turbine, and a recirculation line, which returns to the pump inlet upstream of the inlet strainer via the "cascade" recirculation orifice. The recirculation flow allows the pump to run in a stable and safe condition when there is little or no flow being delivered to the turbine. It is important that the pump is not run only on recirculation flow for an extended period of time. Extended running on pump recirculation only may cause overheating of the pump, or damage to the pump seals. The water flow in the main line next passes through a turbine flowmeter (FM1-1), with triple pick-ups, each with its own Flow Transmitter (96WF-1, 96WF-2, and 96WF-3). The flowmeter provides a signal to the SPEEDTRONICE control system. A strainer (FW1-3) is installed downstream of the flowmeters, to protect the other system components in the event of a flowmeter failure. Manually operated bypass/isolation valves, and a bypass piping loop is provided to allow the flowmeter to be isolated (e.g. for flushing) or to be removed for maintenance (if necessary). Downstream of the flowmeters, the flow passes through a water actuated stop valve (VS2-1), with solenoid control valve (20WN-1), which shuts off water flow in response to a command from the control system. Downstream of the stop valve is a manual isolation valve, followed by the skid discharge connection ("WJ2"). Interconnecting piping (provided by the customer) carries the water flow from the skid discharge to the manifold connection on the turbine base ("WI2"). The manifold distributes flow equally to fourteen flow proportioning valves (VWP1-1 to 14). These valves have a 15 psid (1.0 kg/cm2) cracking pressure, and provide a graduated flow restriction such that the flow resistance is relatively high at low flows. The purpose of the flow proportioning valves is to provide an even flow distribution at start-up and at low flows. The discharge from each of these valves is connected to tubing, which carries the flow of water to one of the combustors.

CONTROL AND MONITORING

Total water flow to the turbine is scheduled as a function of fuel flow to the turbine. A control schedule must be established during field compliance tests to meet emissions limits specified by the applicable local or federal standards. The compliance curve, determined as a result of these tests, is programmed into the SPEEDTRONICE control system. It is used as a reference for comparison to the actual water flow, in order to verify that emissions regulations are being met.

The electronic controllers (micro-computers R, S, and T) in the SPEEDTRONICE, control the flow of water in accordance with the control schedule and compliance control curve. The controllers generate a 4 to 20 mA demand signal to the Variable Frequency Drive, which accurately modulates pump speed to obtain the required flow. The control signal is generated in accordance with the control schedule, to achieve the required emissions levels at that particular operating condition. The skid flowmeter (FM1-1) generates a 4-20 mA output proportional to flow rate, which the SPEEDTRONICE uses in the flow control loop as a feedback signal.

ATTACHMENT SH-EU2-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

FUEL GAS CONTROL SYSTEM (DLN_X 2.6)

This attachment provides a general description of Dry Low NO_X system's operation as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU2-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

FUEL GAS SYSTEM (DLN 2.6)

GENERAL

The Stop/Speed Ratio Valve (SRV) and the Gas Control Valves (GCVs) work in conjunction to regulate the total fuel flow delivered to the gas turbine. This arrangement uses four separate Gas Control Valves to control the distribution of the fuel flow to a multi-nozzle combustion system. (See Gas Fuel System schematic) The GCVs control the desired fuel flow in response to a control system fuel command, Fuel Stroke Reference (FSR). The response of the fuel flow to GCVs' commands is made predictable by maintaining a predetermined pressure upstream of the GCVs. The GCVs' upstream pressure, P2 , is controlled by modulating the SRV based on turbine speed as a percentage of full speed, TNH, and feedback from the P2 pressure transducers, 96FG-2A, B, and C. Refer to the Gas Fuel System schematic. In a Dry Low NOx 2.6 (DLN-2.6) combustion system there are four gas fuel system manifolds: Premix 1 (PM1), Premix 2 (PM2), Premix 3 (PM3), and Quarternary (Q). Each combustion chamber has a total of six fuel nozzles. The PM1 gas fuel delivery system consists of one diffusion type fuel nozzle for each combustion chamber. The PM2 gas fuel delivery system consists of two premix type fuel nozzles for each combustion chamber. The Quarternary gas fuel delivery system consists of injection pegs located in each combustion casing. The PM3 gas fuel delivery system consists of three premix type fuel nozzles for each combustion chamber. The GCVs regulate the percentage of the total fuel flow delivered to each of the gas fuel system manifolds.

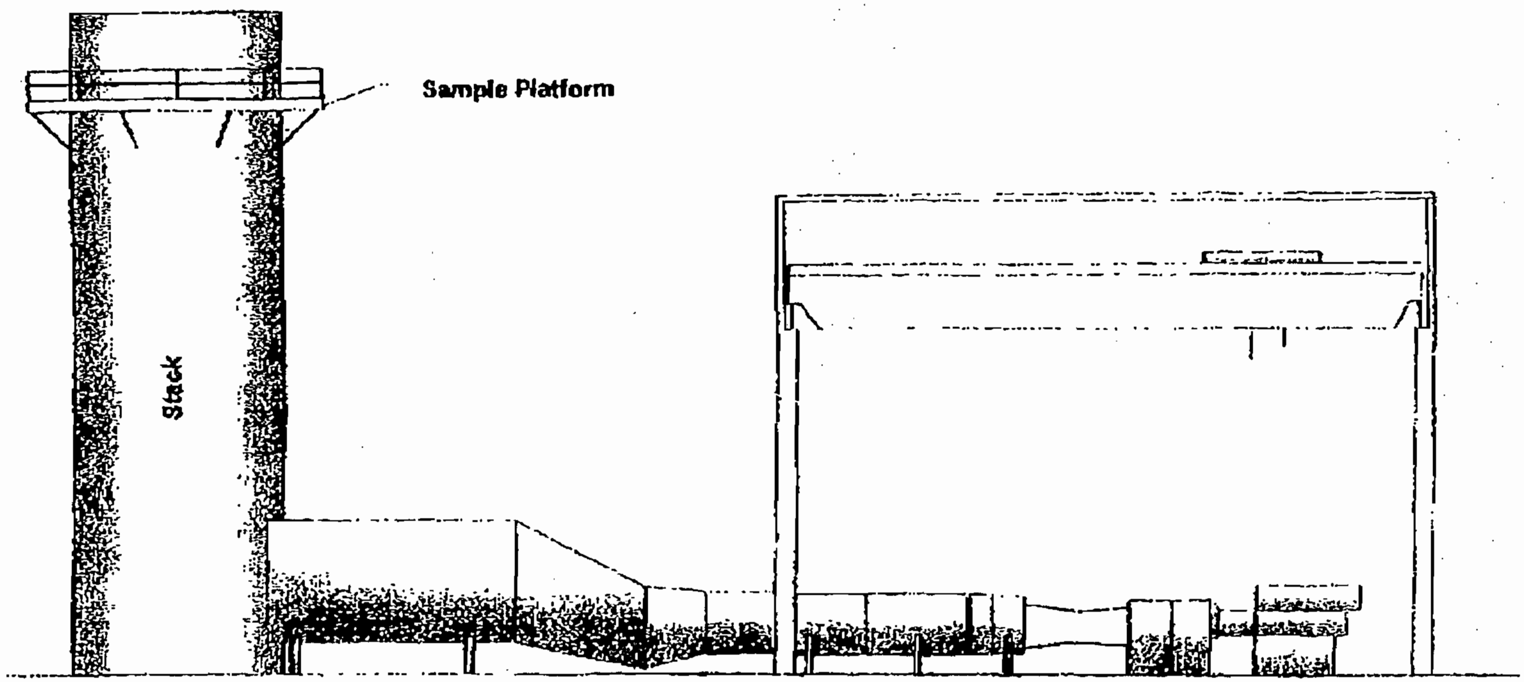
FUEL GAS CONTROL SYSTEM

The GCVs and SRV are actuated by hydraulic cylinders moving against spring loaded valve plugs. Three coil servo valves are driven by electrical signals from the control system to regulate the hydraulic fluid in the actuator cylinders. Redundant sensors in the form of Linear Variable Differential Transformers (LVDTs) mounted on each valve provide the control system with valve position feedback for closed loop position control. A functional explanation of each part or subsystem is contained in subsequent paragraphs. For more detail on the electro-hydraulic circuits see the SPEEDTRONIC System text, Gas Fuel system schematics, and Control Sequence Programs furnished to the site.

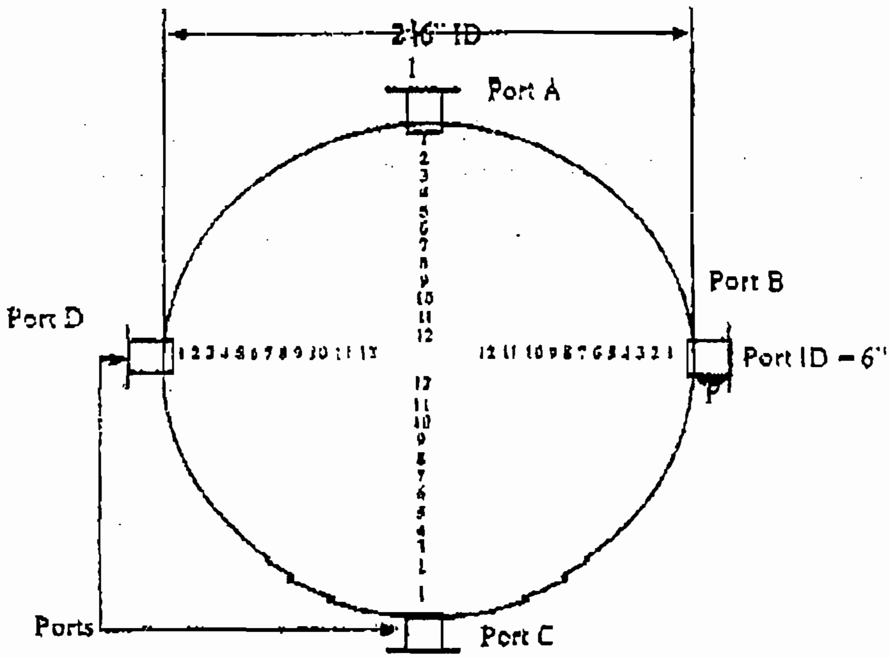
Gas Control Valves

The plugs in the GCVs are contoured to provide the proper flow area in relation to valve stroke. The combined position of the control valves is intended to be proportional to FSR. The GCVs use a skirted valve disc and venturi seat to obtain adequate pressure recovery. High pressure recovery occurs at valve pressure ratios substantially less than the critical pressure ratio. The result is that the flow through the GCVs is independent of the pressure drop across the valves and is a function of valve inlet pressure, P2, and valve area only. The control system's fuel command, FSR, is the percentage of maximum fuel flow required by the control system to maintain either speed, load, or another setpoint. FSR is broken down into two parts which make up the fuel split setpoint, FSR1 and FSR2. FSR1 is the percentage of maximum fuel flow required from the Liquid Fuel System and FSR2 is the percentage of maximum fuel flow required from the Gas Fuel System. FSR2 is also broken down into four parts, FSRPM1, FSRPM2, FSRPM3 and FSRQT. FSRPM1 is the percentage of FSR2 controlling the GCV1 gas fuel valve. FSRPM2 is the percentage of FSR2 to be directed to the GCV2 gas fuel valves, and so on. FSRPM1 is used as a reference to a servo amplifier, which drives the coils of GCV #1. FSRPM2 is used to drive the coils of GCV #2, and so on.

ATTACHMENT SH-EU2-J4
DESCRIPTION OF STACK SAMPLING FACILITIES



GENERAL ARRANGEMENT



Traverse Point	% of Diameter from near wall	Distance from Inner Wall (inches)
1	1.1	2.1
2	3.2	6.9
3	5.5	11.9
4	7.9	17.1
5	10.5	22.7
6	13.2	28.5
7	16.1	34.8
8	19.4	41.9
9	23.0	49.7
10	27.2	58.8
11	32.3	69.8
12	39.8	86.0

Figure - . Traverse point sampling CEMS

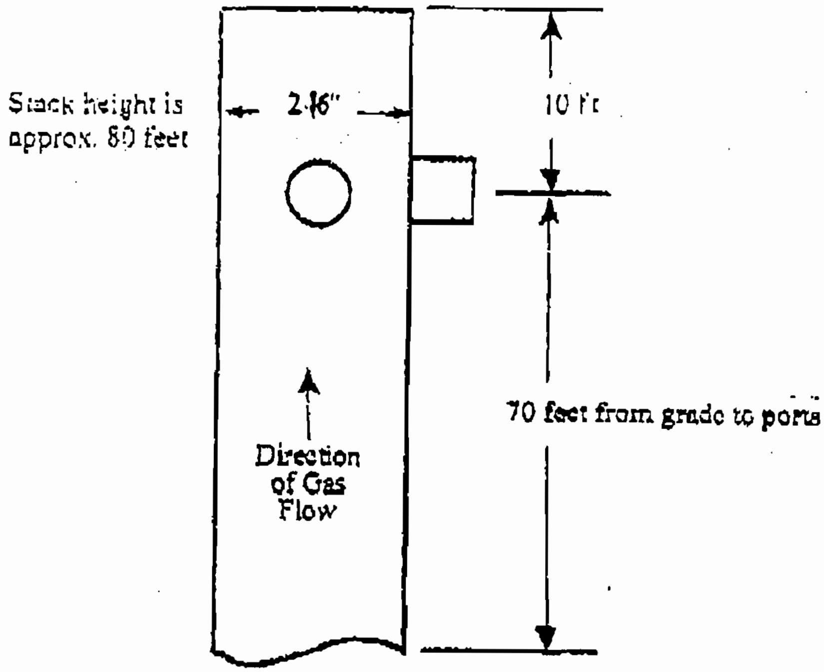


Figure - . Stack sample location.

ATTACHMENT SH-EU2-J6

PROCEDURES FOR STARTUP/SHUTDOWN

This attachment provides a general description of the startup and shutdown procedures as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

OPS-023 COMBUSTION TURBINE STARTUP

Shady Hills, FL
GE Contractual Services
Effective Date: Pending

Number: OPS-023
Attachment SH-EU2-J6a.doc

I. **SCOPE**

A. The purpose of this procedure is to provide safe means of Startup of the Gas Turbine Generators.

II. **DEFINITIONS**

A. None.

III. **RESPONSIBILITIES**

A. Facility Management

1. To revise this procedure when new safety measures and operating techniques or technologies become available.

B. Employee

1. To implement this operation by utilizing verbatim compliance of this procedure.

2. To use this procedure in parallel with all approved safety procedures.

3. To notify supervision when any unsafe or abnormal condition presents itself.

IV. **GUIDELINES**

A. Start required BOP Equipment

1. Start closed cooling water in accordance with OPS-031.

2. Start raw water for evap coolers in accordance with OPS-028.

3. Verify fuel systems are aligned in accordance with VLU's.

4. Start demin transfer pump in accordance with OPS-050.

5. Verify Compressed air system is online in accordance with OPS-037.

6. Verify gas heater is aligned and ready for operation in accordance with OPS-035.

7. Refer to OPS-044 for instructions on synchronizing.

B. Select "Main" display from the demand display.

1. HMI: Shutdown Status
Off Cool down or ON Cool down
Off

C. Select "Auto synchronize" ON

D. Select "Water Injection" ON

E. Select fuel to be used for start-up

F. Select "Auto" or "Remote" Depending on start location then "Execute".

1. "HMI: Startup Status
Ready to Start
Auto

G. Select "Start" and " Execute":

1. Unit Auxiliaries will be started lube oil flow will be established.

a. HMI: Seq in progress

2. When permissives are satisfied (L4) will be satisfied.

a. HMI: Startup Status
Starting
Auto; Start

3. When inot in cool down turning gear will engage, when unit realized approx. 6 rpm starting device will be energized and accelerate the unit.

a. HMI: Startup Status Crank

4. When unit reaches 15% speed "14 HM" will appear on HMI at this time unit will purge for 5 minutes.

5. FSR will be set to firing valve. Ignition sequence is initiated.

a. HMI: Startup Status/Firing

6. Flame established HMI; display will indicate flame in those combustors with flame detectors.

7. Select "Base Load"

8. FSR set back to warm-up valve.

a. HMI: Startup Status/Warming up

NOTE

If flame goes out during the 60-second firing period, FSR will be reset to firing valve. At this time you may shut the unit down or attempt to fire again to fire again select CRANK on main display.

9. At the end of the warm up period, with flame established, FSR will increase.

a. HMI: Start-up Status/Accelerating 50% speed "14HA" will be displayed on HMI.

10. Turbine will continue to accelerate, at 85-90% starting device will disengage and shutdown.

    a. HMI: Startup control to speed control at approx 60% speed.

11. When turbine reaches operating speed "14HS" will be on HMI, field flashing is then terminated, if software switch (43S) is in off and remote is not selected on HMI.

    a. HMI: Run Status
       Full Speed No Load
       Auto; Start

12. If 43S is in auto or remote on HMI; Automatic Sync is initiated.

    a. HMI: Synchronizing

H. Normal Load Operation: Refer to OPS-043

NOTE:
Operator should monitor mode changes for proper DLN operation and indication of flame. Also monitor vibration screen for any extreme changes.

V. TRAINING

A. Complete Control Room Operator Qualifications.

VI. **REFERENCES**

A. GEK 107357 (GE Operations and Maintenance Manuel)
B. OPS-043
C. OPS-044

VII. **APPENDIX**

A. None

OPS-024 COMBUSTION TURBINE STARTUP

Shady Hills, FL
GE Contractual Services
Effective Date: Pending

Number: OPS-024
Attachment SH-EU2-J6b.doc

I. SCOPE

A. The purpose of this procedure is to provide safe means of shutting down the Gas Turbine Generators.

II. DEFINITIONS

A. None

III. RESPONSIBILITIES

A. Facility Management

1. To revise this procedure when new safety measures and operating techniques or technologies become available.

B. Employee

1. To implement this operation by utilizing verbatim compliance of this procedure.

2. To use this procedure in parallel with all approved safety procedures.

3. To notify supervision when any unsafe or abnormal condition presents itself.

IV. GUIDELINES

A. Select STOP on the <I> /HMI Main Display.

1. The unit will automatically unload, reduce speed, and chop fuel at part speed, and initation of cooldown sequence as unit coasts to a stop.

B. Immediately following shutdown verify unit is on turning gear to ensure minimum protection against rubs and unbalance on subsequent starting attempt.
G.E. recommends 48 hrs, prior to taking off cool down.

C. Shut down and isolate associated BOP equipment in accordance with procedures.

D. If this is the last unit to be shutdown refer to OPS-022 for supply systems to be shut down.

E. Upon completion of supply systems shutdown perform the following.

1. Walk unit down and inspect for leaks and any broken equipment.
2. Take a set of logs.
3. Verify unit is ready to start at HMI.
4. Clear any alarms, and investigate problems and correct.

V. TRAINING

A. Complete SR. Operations qualification.

VI. REFERENCES

A. GE Operations and Maintenance Manuals

ATTACHMENT SH-EU2-J7

OPERATION AND MAINTENANCE PLAN
FUEL GAS SYSTEM

This attachment provides a general description of operation and maintenance procedures as recommended by General Electric. Actual operation and maintenance plans will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU2-J7

OPERATION AND MAINTENANCE PLAN

FUEL GAS SYSTEM

GENERAL

The dry low NOx 2.6 (DLN-2.6) control system regulates the distribution of fuel delivered to a rnulti-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion chamber fuel nozzle assembly is calculated to maintain unit load and fuel split for optimal turbine emissions.

GAS FUEL SYSTEM

The DLN 2.6 Combustion system consists of six fuel nozzles per combustion can, each operating us a fully premixed combustor, five located radially, one located in the center. The center nozzle, identified as PM 1, (PreMix 1), two outer nozzles located adjacent to the crossfire tubes, identified as PM2, (PreMix 2), and the remaining three outer nozzles, identified as PM3, (PreMix 3). Another fuel passage, located in the airflow upstream of the premix nozzles, circumferentially around the combustion can, is identified as the quaternary fuel pegs, The fuel flow to the six fuel nozzles and quaternary pegs are controlled by four independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one, (PM1), gas control valve two (PM2), gas control valve three, (PM3), and gas control valve four, (Quat). The stop/ratio valve (SRV) is designed to maintain a predetermined pressure, (P2), at the inlet of the gas control valves. Gas control valves one through four, (GCVI-4), regulate the desired gas fuel flow delivered to the turbine in response to the command signal FSR, (Fuel Stroke Reference), from the SPEEDTRONIC panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. This flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software. The stop ratio valve and gas control valves are monitored for their ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to Warn the operator. If the condition persists for an extended amount of time, the turbine will be tripped and another alarm will annunciate the trip.

CHAMBER ARRANGEMENT

The 7F machine employs 14 combustors while the 9F employs 18 similar but slightly larger combustors. For each machine there are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent combustors. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi-nozzle cap assembly, liner assembly, and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion can, porting fuel to casing injection pegs located radially around the casing.

ATTACHMENT SH-EU2-J7

OPERATION AND MAINTENANCE PLAN
LIQUID FUEL SYSTEM

This attachment provides a general description of operation and maintenance procedures as recommended by General Electric. Actual operation and maintenance plans will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU2-J7

OPERATION AND MAINTENANCE PLAN

LIQUID FUEL SYSTEM

GENERAL

The liquid fuel (distillate oil) system filters, pressurizes, controls, and equally distributes fuel flow to the fourteen turbine combustion chambers. Flow is regulated by controlling the position of 3-way valve VC3-1. The entire liquid fuel system must be pressurized, with all valves in the open position, before starting the gas turbine. The liquid fuel system should be operated for a minimum of one half hour every week to prevent binding of the components. This is best achieved by operation of the turbine on liquid fuel for a minimum of one half hour per week with either 100% fuel oil or fuel gas mixed mode with fuel oil. The fuel system is comprised of the following major components:

1. Duplex low-pressure fuel filter FF1-l, -2 with transfer valve VM5-l and thermal pressure relief valves VR41-1, -2.
2. Fuel pump PF1-l with driving motor 88FP-1 and motor heater 23FP-l and discharge pressure relief valve VR4-1.
3. Fuel flow control valve VC3-1.
4. Fuel stop valve VS1-1.
5. Fuel flow divider FD1-1.
6. Nozzle pressure selector valve VH17-l.
7. Check valves VCKI-l through 14.
8. Fuel nozzle assemblies.
9. Except for the check valves and fuel nozzles all components are mounted in the off-base liquid, fuel/atomizing air module.

FUNCTIONAL DESCRIPTION

Duplex Low-Pressure Fuel Filter

Fuel oil forwarded to the liquid fuel module within specified pressure and temperature ranges enters the low pressure filter FF1-l or FFI-2 via transfer valve VM5-1 prior to entering the fuel pumps. The low-pressure filter consists of multiple five-micron synthetic elements with oversize contamination capacity. These elements retain contaminants, which could damage downstream components. The filter vessels are protected from thermal overpressure by relief valves VR41-1, -2. Differential pressure switch 63LF-5 gives a signal when the pressure drop across the filter reaches 15 psid (103 kPad). The ditty filter should then be serviced by replacing the dirty elements with clean ones.

Fuel Pump

Fuel pump PFI-1 is of the axial flow, positive displacement, rotary, screw type with one power rotor (driven screw) and two intermeshing idler rotors. The single ball bearing positions the power rotor for proper operation of the mechanical seal. The bearing is permanently "'grease packed and external to the pumped fuel. The motor driven fuel pump 88FP/PFI-1 is rated at one hundred percent capacity of the maximum turbine fuel requirement. The pump motor is equipped with an integral heater 23FP-l. The pump is protected from insufficient suction pressure by permissive-to-start pressure switch 63FL.2. During normal operation this switch functions as a low-pressure alarm. The fuel system is protected from excessive pressure by pump discharge relief valve VR4-1 that relieves pressure back to filter inlet.

Fuel Flow Control Valve

Pump discharge flow is modulated by the servocontrolled three-way control valve assembly VC3-1. Components of this assembly include the valve body, electrohydraulic servovalve 65FP-1, hydraulic oil fi1ter FH3-1 and the cylinder. The valve controls the flow to the turbine by throttling the main port while opening the bypass port, returning the bypass flow to pump suction.

Liquid Fuel Stop Valve

Hydraulically operated three-way fuel oil stop valve VS1-1 shuts off the supply of fuel to the turbine during normal or emergency shutdowns. During normal turbine operation, the valve is held open (bypass closed) by high-pressure hydraulic oil that passes through a hydraulic trip relay (dump) valve VH4-1. This dump valve, located between the hydraulic supply and the stop valve hydraulic cylinder, is hydraulically operated by trip oil acting through solenoid valve 20FL-l. During a normal shutdown or emergency trip, low trip oil pressure will cause valve VH4-1 to shift position, dumping high-pressure hydraulic oil from the stop valve actuating cylinder, allowing the stop valve spring to close the valve. During an electrical trip, solenoid valve 20FL-l causes the dump valve to shift with the same results as above. The stop valve will be fully closed within 0.5 second of the trip signal. Limit switch 33FL-l signals stop valve closed position.

Flow Divider

Flow divider FD1-1 equally distributes filtered fuel to the 14 combustors. It is a continuous flow, free wheeling device consisting of fourteen gear pump elements in a circular or linear arrangement having a common inlet with a single timing gear or shaft. This timing (sun) gear or shaft maintains the speed of each flow element synchronous with all the other elements.

The speed of each flow divider gear element is directly proportional to the total flow through the flow divider. Magnetic pickup assemblies 77FD-l, -2 and -3, fitted to the flow divider, produce a flow feedback signal at a frequency proportional to the fuel delivered to thc combustion chambers. This signal is fed to the SPEEDTRONICE control panel where it is used in the fuel control system.

Pressure Selector Valve

An eighteen position pressure selector valve VH17-l allows monitoring of individually selected line pressures on a local gauge. These include: anyone of the fourteen combustor fuel lines; pump discharge pressure; and flow divider inlet pressure.

Check Valves

Check valves VCKI-l through 14 isolate the fuel nozzles during shutdown periods to prevent line drainage and flow communication between combustors.

ATTACHMENT SH-EU2-J14
COMPLIANCE ASSURANCE MONITORING PLAN

ATTACHMENT SH-EU2-J14

COMPLIANCE ASSURANCE MONITORING PLAN

The only control device for the CT is water injection for NO_x control. Continuous Emission Monitors (CEMS) monitor NO_x, therefore the Compliance Assurance Monitoring Plan is not applicable.

ATTACHMENT SH-EU2-J15

ACID RAIN PART APPLICATION

Golder Associates Inc.

5100 West Lemon Street, Suite 114
Tampa, FL USA 33609
Telephone (813) 287-1717
Fax (813) 287-1716

Golder Associates

November 12, 2001

Project No.013-9517

Mr. Bob Miller
US EPA Clean Air Markets
Mail Code 6204J
501 3rd Street, NW
Washington, DC 20001

RE: Acid Rain Permit
Shady Hills Power Company, L.L.C.
Shady Hills Generating Station
Pasco County, Florida

Dear Mr. Miller:

Enclosed is notification of a change in the designated representative and alternate designated representative for the above referenced project. Please find The Certificate of Representation [EPA Form 7610-1(rev.4-98)], which identifies Mr. James M. Packer, Director of Operations and Mr. John E. Dorsett, Vice President of Business Development/Operations, Shady Hills Power Company, L.L.C. as the designated representative and alternate designated representative, respectively.

Shady Hills Power Company, L.L.C. and Golder Associates Inc. appreciate your assistance in processing the above referenced information. If you have any questions or need additional information, please contact me at (813) 287-1717.

Very truly yours,

GOLDER ASSOCIATES INC.

Manitia Moultrie
Senior Project Manager

MM/AT/nd

Enclosures

cc: Mr. Scott Sheplak, Florida Department of Environmental Protection
Mr. Jimmy Packer, Mirant Corporation
Mr. Chuck Jordan, Mirant Corporation
Mr. Glenn Keeling, Mirant Corporation

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United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

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
Shady Hills Generating Station	FL	55414

STEP 2
Enter requested information for the designated representative.

Name: James M. Packer, Shady Hills Power Company, L.L.C.	
Address: 1155 Perimeter Center West Atlanta, Georgia 30338-5416	
Phone Number: (678) 579-7962	Fax Number: (678) 579-7358
E-mail address (if available): jimmy.packer@mirant.com	

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

Name: John E. Dorsett	
Phone Number: (678) 579-7349	Fax Number: (678) 579-7358
E-mail address (if available): eddie.dorsett@mirant.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 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.

Shady Hills Generating Station
Plant Name (from Step 1)

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.

James M. Packer Signature (designated representative)	11-07-01 Date
Signature (alternate designated representative)	11-08-01 Date

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.

Shady Hills Power Company, L.L.C. Name					☒ Owner ☐ Operator	
CT1 ID#	CT2 ID#	CT3 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#

Name					☐ Owner ☐ Operator	
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

EL PASO MERCHANT ENERGY

November 21, 2000

Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399
MS 5505

Attention: Mr. Scott Sheplak, P.E.

RE: Acid Rain Program, Phase II Permit Application
Shady Hills Power Company, L.L.C. – Shady Hills Generating Station

Dear Mr. Sheplak:

Please find attached a Phase II Permit Application for the Shady Hills Generating Station located in Pasco County, Florida that is owned and operated by the Shady Hills Power Company, L.L.C. With one exception, this certificate is submitted in accordance with the provisions of Title 40, Parts 72.30 and 72.31 of the Code of Federal Regulations applicable to facilities regulated by the Acid Rain Program. This exception is in regard to the date of submission described in the regulation as the later of 24 months prior to January 1, 2000 or 24 months prior to the unit commencing operation. Due to the short period of time before the anticipated start of operation for the facility (January 2002), Shady Hills Power Company, L.L.C. was unable to meet this deadline.

Also, please find attached a copy of the Certificate of Representation form as the original was sent to the US EPA.

If you have any questions concerning the attached information, please call me at the phone number provided.

Sincerely,
Shady Hills Power Company, L.L.C.

John J. O'Rourke
V. P. and Managing Director
Venture Management

Enclosures

COPY

BEST AVAILABLE COPY

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 Shady Hills Generating Station State FL ORIS Code 55414

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	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
GT 101	Yes		Jan 29, 2002	April 30, 2002
GT 201	Yes		Jan 29, 2002	April , 2002
GT 301	Yes		Mar 1, 2002	Jun 1, 2002

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.

Shady Hills Generating Station

Plant Name (from Step 1)

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Shady Hills Generating Station

Plant Name (from Step 1)

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 Mr. John O'Rourke	
Signature J J O'Rourke	Date 11/27/00

STEP 5 (optional)
Enter the source AIRS
FINDS identification

AIRS	
FINDS	

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

GE Frame 7FA Combustion Turbine

4. Emissions Unit Identification Number: [ ] No ID
ID: **003** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**April 2002**	**49**	[X]

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

This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment SH-EU3-A9.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

   Dry Low NO_x combustion - Natural gas firing

   Water injection - Distillate oil firing

2. Control Device or Method Code(s): **25, 28**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **General Electric** Model Number: **7FA**
2. Generator Nameplate Rating: **172** MW
3. Incinerator Information:
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			**1,858**	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		days/week
		weeks/year	**5,000**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum heat input at 100% load and 32°F oil firing (LHV).
Maximum for gas firing is 1,670 MMBtu/hr at 100% load and 32°F (LHV).
The CTs will operate no more than an average of 3,390 hrs/CT/yr.
No single CT will operate > 5,000 hrs per year.
See Attachment SH-EU3-B6 for performance specifications and manufacturer guarantees.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment SH-EU3-D	

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? **CT3**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,645,000**	10. Water Vapor: **8.6** %
11. Maximum Dry Standard Flow Rate: **800,000** dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **347.0** North (km): **3139.0**		
14. Emission Point Comment (limit to 200 characters): **Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.**		

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): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **13.7**	5. Maximum Annual Rate: **13,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 131.8 (rounded to 132). Based on 7.1 lb/gal; LHV of 18,560 Btu/lb, ISO conditions, 1,000 hrs/yr operation. The amount of fuel oil burned (BTU's) will not exceed the amount of natural gas burned (BTU's) per year.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.70**	5. Maximum Annual Rate: **5,752**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025	028	EL
CO			EL
VOC			EL
PM_{10}			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if < 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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 **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load;TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 101.5 lb/hour 55.3 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See PSD Air Construction Permit Application; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.	

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: See Comment	4. Equivalent Allowable Emissions: 5.1 lb/hour 8.4 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 grain/100 cf - 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

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: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **3-Hour Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **24-Hour Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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**	4. Equivalent Allowable Emissions: **74.4** lb/hour **35.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **7 ppmvw**	4. Equivalent Allowable Emissions: **16.7** lb/hour **8.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 – CO Test**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 – CO Test**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**

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

See PSD Air Construction Permit Application; Section 2.0; Appendix A.

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

Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions

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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Method 5 or 17; if <400 hours

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

Oil firing - all loads; 1,000 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

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 **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See PSD Air Construction Permit Application; Section 2.0; Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other **(BACT)**
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **VE Test serves as a surrogate for PM/PM_{10} compliance testing.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Horiba** Model Number: **ENDA-E4220LS**	Serial Number: **11527**
5. Installation Date: **01 Nov 2001**	6. Performance Specification Test Date: **15 Feb 2002**
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **2 hrs/24 hrs** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-210.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Horiba** Model Number: **ENDA-E4220LS** Serial Number: **11527**	
5. Installation Date: **01 Nov 2001**	6. Performance Specification Test Date: **15 Feb 2002**
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: Water/Fuel Ratio. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: SH-EU3-J1 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: SH-EU3-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: SH-EU3-J3 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: SH-EU3-J4 [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [X] Attached, Document ID: SH-EU3-J5 [ ] Previously submitted, Date:_________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: SH-EU3-J6 [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [X] Attached, Document ID: SH-EU3-J7 [ ] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:______ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:______ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [X] Not Applicable

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

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

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

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

[X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID: SH-EU3-J15

[ ] 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

ATTACHMENT SH-EU3-A9

EMISSIONS UNIT COMMENT

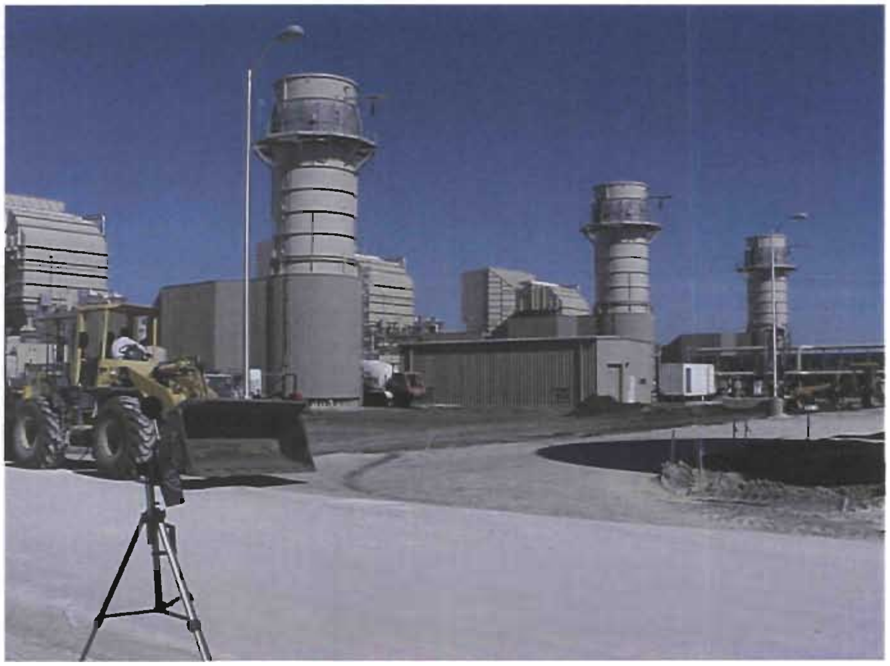


Photo 1. Diagonal View - Combustion Turbine

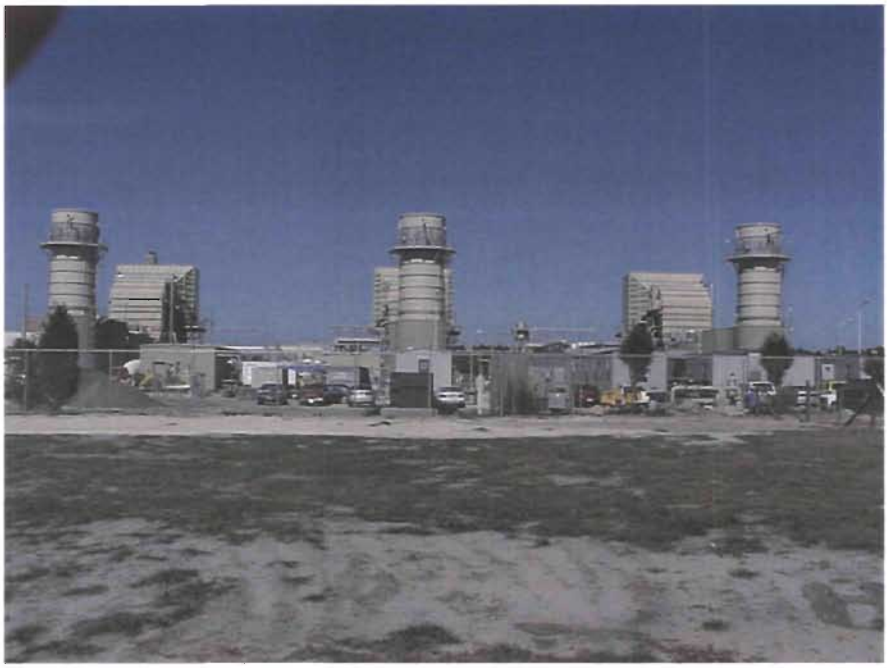


Photo 2. Front View - Combustion Turbine

Attachment SH-EU3-A9
Shady Hills Generating Station Photos

Source: Golder, 2002.

Golder Associates

ATTACHMENT SH-EU3-B6
OPERATING CAPACITY/SCHEDULE COMMENT

2. Performance Guarantees

2.1 Guaranteed Performance

Operating Point	Fuel	Output (kW)	Heat Rate (Btu/kWh, LHV)
Baseload, 95°F, 64% RH	Natural Gas	154,100	9,680
Baseload, 95°F, 64% RH	Distillate Oil	165,500	10,150
Heat Rate = Fuel Consumption (Btu/h, LHV) / Output (kW)			

2.1.1 Basis For Equipment Performance

The performance guarantees listed above are based on the scope of equipment supply as defined in this proposal and as stated for the following operating conditions and cycle parameters:

a. The natural gas fuel and distillate fuel oil are in compliance with Seller's Gas Fuel Specification GEI-41040F and Liquid Fuel Specification 41047H respectively and supplementary Fuel, Air and Steam Purity Requirements as defined in this proposal.

b. Natural Gas Fuel Heating Value = 20,773 Btu/lb (LHV)

c. Distillate Fuel Oil Heating Value = 18,300 Btu/lb (LHV)

d. Site Elevation = 50 ft

e. Site Pressure = 14.67 psia.

f. Inlet Loss = 4.0 in Water

g. Exhaust Loss = 5.5 in Water

h. Evaporative Cooler = On, with 85% effectiveness

i. Fuel Gas Supply Temperature = 80°F (@ GT stop valve)

j. Fuel Gas Supply Pressure = 450 psig - 475 psig (@ GT stop valve)

k. Gas turbines are operating at steady state baseload.

l. Tests to demonstrate guaranteed performance shall be conducted in accordance with the ASME Performance Test Procedure as defined in this proposal (GEK-41067D).

m. Generator power factor for baseload operation = .85 lagging.

n. Performance is measured at the generator terminals and includes allowances for excitation power and the shaft-driven equipment normally supplied.

o. Station services for GE supplied auxiliaries are not included in the guaranteed performance.

p. The equipment is in a new and clean condition (less than 100 fire hours of operation).

q. Performance curves such as ambient effects curves and generator efficiency curves will be provided after contract award. These curves are to be used during the site performance test to correct performance readings back to the site conditions at which the performance guarantees were provided. Where available, typical correction curves have been supplied.

r. Natural gas performance is based on operation with a dry low NOx combustion system without gas turbine diluent injection for NOx control.

s. Distillate fuel oil performance is based on diluent injection flow rate of 93,890 lb/hr. The actual amount of diluent injection as determined during the field compliance test may be different, which will have an effect on the output and heat rate.

t. Compressor air extraction from gas turbine = 0.

u. Natural Gas Analysis (%vol) =

Nitrogen	0.2441	Propane	0.8050	Pentane	0.0329
CO2	0.9672	I-Butane	0.1956	Hexane	0.0855
Methane	94.7081	Butane	0.1754		
Ethane	2.7296	I-Pentane	0.0565		

v. A nominal distillate oil analysis was assumed for the guarantees.

2.2 Emissions Guarantees

Exhaust gas emissions shall not exceed the following concentrations during steady-state operation from baseload down to 50% CT load over the ambient temperature range from 20°F to 100°F for each of the gas turbines:

	Natural Gas	Distillate Oil
NOx, ppmvd Ref. 15% O_2, ISO	9	42
CO, ppmvd	12	20
VOC, ppmvw	1.4	3.5
Particulates (TSP - front half only), lb/hr	9	17
Opacity	10%	20%

2.2.1 Basis For Emissions Guarantees

a. The natural gas fuel and distillate fuel oil are in compliance with Seller's Gas Fuel Specification GEI-41040F and Liquid Fuel Specification 41047H respectively and supplementary Fuel, Air and Steam Purity Requirements as defined in this proposal.

b. Testing and system adjustments are conducted in accordance with GEK-28172F, Standard Field Testing Procedure for Emissions Compliance included in the Reference Specifications/Documents Tab of this proposal.

c. Ambient air pressure = 14.67 psia

d. Emissions are per gas turbine on a one hour average basis.

e. Fuel bound nitrogen = 0% on NG; maximum of 0.015% (by wt) on distillate fuel oil

f. Fuel ash content = 0%

g. Sulfur emissions are a function of the sulfur present in the incoming air and fuel flows. Since the gas turbine(s) have no influence on the sulfur emissions when no sulfur is present in the fuel, sulfur based emissions are not guaranteed

h. GE reserves the right to determine the emission rates on a net basis wherein emissions at the gas turbine inlet are subtracted from the measured exhaust emission rate if required to demonstrate guarantee rate.

ATTACHMENT SH-EU3-D

APPLICABLE REQUIREMENTS

ATTACHMENT SH-EU3-D

Applicable Requirements Listing

EMISSION UNIT ID: EU3

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	NSPS Subpart GG
62-204.800(7)(c) (State Only)	NSPS authority
62-204.800(7)(d)(State Only)	NSPS General Provisions
62-204.800(12) (State Only)	Acid Rain Program
62-204.800(13) (State Only)	Allowances
62-204.800(14) (State Only)	Acid Rain Program Monitoring
62-204.800(16) (State Only)	Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	Circumvention; EUs with control device
62-210.700(1)	Excess Emissions;
62-210.700(4)	Excess Emissions; poor maintenance
62-210.700(6)	Excess Emissions; notification

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320	All Acid Rain Units (Application Shield)
62-214.330(1)(a)	Compliance Options (if 214.430)
62-214.340	Exemptions (retired units)
62-214.350(2);(3);(5);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)	All Units (Operating Rate)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)	All Units (Applicable Test Procedures)
62-297.310(5)	All Units (Determination of Process Variables)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)
62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels

62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.	Annual Test
62-297.310(7)(a)5.	PM exemption if <400 hrs/yr
62-297.310(7)(a)8.	VE Compliance Test if > 400 hrs/yr
62-297.310(7)(a)9.	FDEP Notification - 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Requirements
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(d)	Performance Test Notification
40 CFR 60.8(e)	Provide Stack Sampling Facilities
40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention
40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)

Acid Rain-Permits:

40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iv)	SO_2 Allowances-Phase II Units
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS

40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID;unit/system ID
40 CFR 72.33(c)	Dispatch System ID;ID requirements
40 CFR 72.33(d)	Dispatch System ID;ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	Compliance Dates;
40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(c)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)

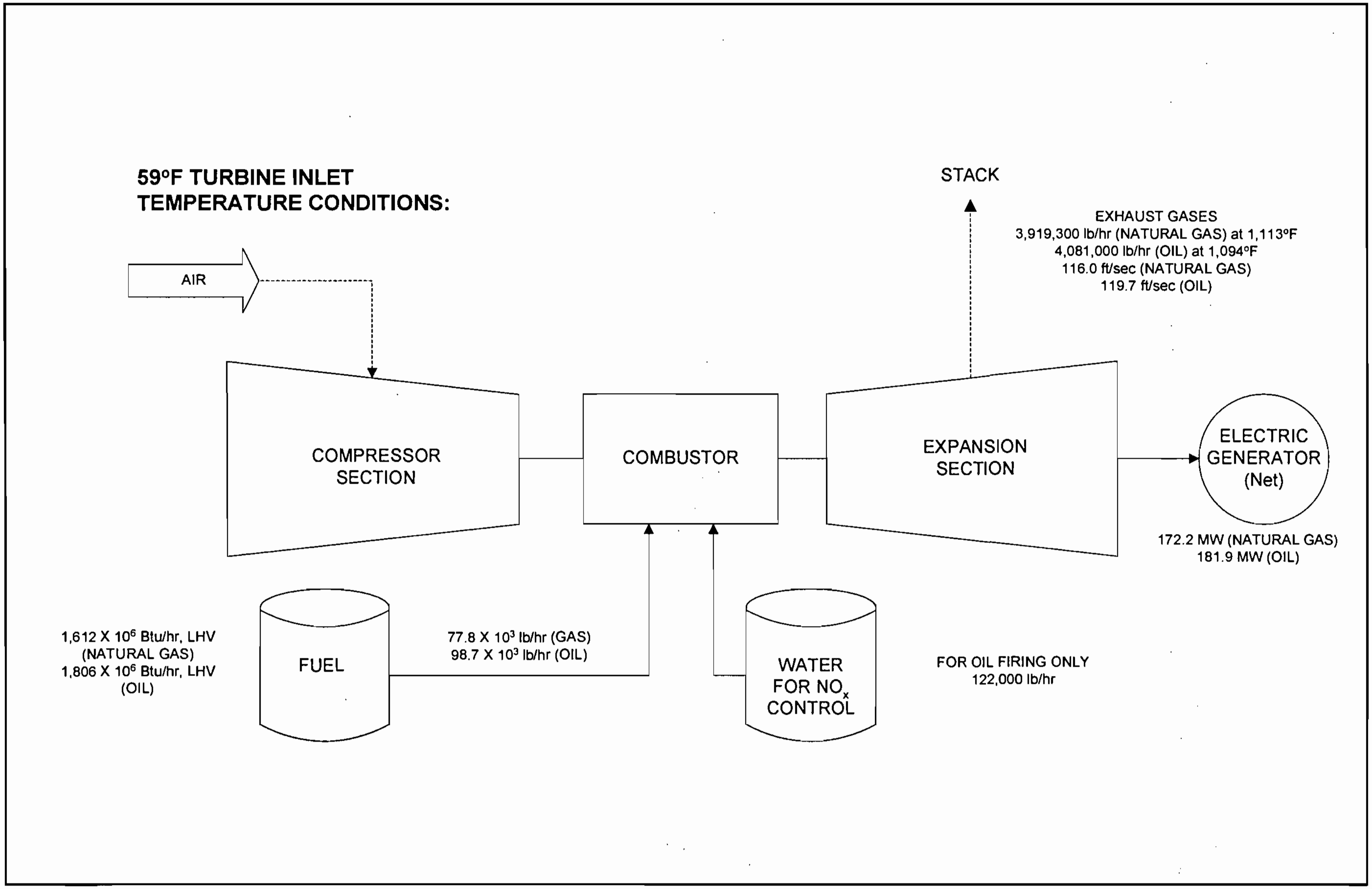
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; CO_2
40 CFR 75.30(d)	General Missing Data Procedures; SO_2
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.53	Monitoring Plan; revisions
40 CFR 75.57(a)	Recordkeeping Requirements for Affected Sources
40 CFR 75.57(b)	Operating Parameter Record Provisions
40 CFR 75.57(d)	NO_x Emission Record Provisions
40 CFR 75.57(e)	CO_2 Emission Record Provisions
40 CFR 75.57(h)	Missing Data Records
40 CFR 75.58(c)	Specific SO_2 Emission Record Provisions
40 CFR 75.58(e)	Specific SO_2 Emission Record Provisions
40 CFR 75.59	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.64(f)	Method of Submission
40 CFR 75.64(g)	Submission Requirements
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A	Specifications and Test Procedures
Appendix B	QA/QC Procedures
Appendix C.	Missing Data Estimation Procedures
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures

Acid Rain Program-Excess Emissions:

40 CFR 77.3	Offset Plans
40 CFR 77.5(b)	Deductions of Allowances
40 CFR 77.6	Excess Emissions Penalties (SO_2)

ATTACHMENT SH-EU3-J1

PROCESS FLOW DIAGRAM



Attachment SH-EU3-J1
Simplified Flow Diagram of GE Frame 7FA
Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 0139517/4/4.4/4.4.1/SH-EU3-J1
Date: 3/29/02

Golder Associates

ATTACHMENT SH-EU3-J2

FUEL SPECIFICATION

NO. 2 FUEL OIL

Table 2 - Liquid Fuel Specifications

				True Distillates (b)		Ash-Bearing Fuels (b)	
Applicability	**Property**	**Point of Applicability (a)**	**ASTM Test Method (c)**	**Light**	**Heavy**	**Crudes and Blended Residual Fuels**	**Heavier Residual Fuels**
3.1 Gas Turbine Requirements	Kin. Viscosity, cSt, 100°F (37.8°C), min	Delivery	D445	.5(d)	1.8	1.8	1.8
	Kin. Viscosity, cSt, 100°F (37.8°C), max (e)	Delivery	D445	5.8	30	160	900
	Kin. Viscosity, cSt, 210°F (98.9°C), max (e)	Delivery	D445	—	4	13	30
	Specific Gravity, 60°F (15.6°C), max	Delivery	D1298	Report	Report	.96	.96(f)
	Flash Point, °F(°C), min (g)	Delivery	D93	Report	Report	Report	Report
	Distillation Temp. 90% Point, °F(°C), max	Delivery	D86	650(338)	Report	—	—
	Pour Point, °F(°), max	Delivery	D97	0 (-18) or 20 (7) below min. ambient	Report	Report	Report
	Hydrogen, Wt %, min (k)	Delivery	(i)	Report	Report	Report	Report
	Carbon Residue, Wt. % (10% Bottoms) max Direct Pressure Atomization	Delivery	D524	.25	—	—	—
	Carbon Residue, Wt. % (100% Sample) max Air Atomization, Low Pressure	Delivery	D524	1.0	1.0	1.0	—
	Carbon Residue, Wt. % (100% Sample), Air Atomization, High Pressure	Delivery	D524	—	—	Report	Report
	Ash, ppm, max	Combustor	D482	50	50	Report	Report
	Trace Metal Contaminants, ppm, max (h)	Combustor	(i)				
	Sodium plus Potassium			1	1	1	1
	Lead			1	1	1	1
	Vanadium (untreated)			.5	.5	.5	.5
	Vanadium (treated 3/1 wt. ratio Mg/V)			—	—	100	500
	Calcium			2	2	10	10
	Other Trace Metals above 5 ppm			Report	Report	Report	Report
The specifications below apply only when specific environmental codes exist							
3.2 Environmental Code Related Requirements	Sulfur, Wt. %, max	Delivery	D129	Compliance to any applicable codes.			
	Nitrogen, Wt. %, max	Delivery	(i)	Fuel-bound nitrogen may be limited to meet any applicable codes on total NO_x emission.			
	Hydrogen, Wt. %, min.	Delivery	(i)	Minimum hydrogen level may be necessary to meet any applicable stack plume opacity limits (k).			
	Ash plus Vanadium, ppm, max.	Delivery	(i)	Ash plus vanadium content of ash-bearing fuels may be limited to meet applicable stack particulate emission codes (l).			

NOTES TO TABLE 2

a. The fuel properties specified refer to the fuel at different points in the overall system:
Delivery — Fuel as delivered to the turbine site.
Fuel Skid — Fuel at inlet of fuel skid at turbine.
Combustor — Fuel at turbine combustors.

b. Typical fuels within each general type are discussed in Appendix A.

c. ASTM Book of Standards, Parts 23 and 24.

d. In the viscosity range of 0.5 cSt to 1.8 cSt, special fuel pumping equipment may be required.

e. The maximum allowable viscosity at the fuel nozzle is 20 cSt for high pressure air atomization and 10 cSt for low pressure air and direct pressure atomization. The fuel may have to be preheated to reach this viscosity, but in no instance shall it be heated above 275°F (135°C). (This maximum fuel temperature of 275°F is allowed only with residual fuels.) The viscosity of the fuel at initial light-off must be at or below 10 cSt.

f. A specific gravity of 0.96 is based on average fuel desalting capability with standard washing systems. Fuels with specific gravities greater than 0.96 may be desalted to the required minimum sodium plus potassium limits by using higher capability desalting equipment (with higher attendant cost) or by increasing the gravity difference between the fuel and wash water by blending the fuel with a compatible distillate.

g. The fuel must comply to all applicable codes for flash point.

h. A total ash less than 3 ppm is acceptable in place of trace metal analysis.

i. No standard reference tests exist; methods used should be mutually acceptable to General Electric and the user.

j. Water content of crude oils should be reduced to the lowest level practical consistent with capability of available fuel treatment equipment, to minimize the chance of corrosion of fuel system components. In no case shall the water content exceed 1.0 vol. %.

k. A minimum hydrogen content is set both to control flame radiation in the combustor and to limit smoke emissions, where the latter is required by local codes. The limits are 12.0% minimum for true distillates and 11.0% for Ash-bearing fuels (11.3% where the carbon residue exceeds 3.5%). In each case it is assumed that the proper combustor and fuel atomization system are used.

Where the hydrogen content of the fuel is below these limits, General Electric should be consulted for appropriate action.

l. Local codes on total stack particulate emissions may set an upper limit on the sum of the ash (non-filterable) in the original fuel plus the vanadium content. The vanadium together with the required magnesium inhibitor may be a major contributor to total stack particulate emissions. In estimating these emissions for comparison with the code, all of he following sources may have to be considered: vanadium, additives, fuel ash and total sulfur in the fuel; non-combustible particulates in the inlet air; solids from any injected steam or water; and particles from in-

ATTACHMENT SH-EU3-J2

FUEL SPECIFICATION

NATURAL GAS

<table>
<tr><th colspan="6">TABLE 2
GAS FUEL SPECIFICATION</th></tr>
<tr><th>FUEL PROPERTIES</th><th colspan="2">MAX</th><th colspan="2">MIN</th><th>NOTES</th></tr>
<tr><td>Lower Heating Value, Btu/lb</td><td colspan="2">None</td><td colspan="2">100 – 300</td><td>See note 3</td></tr>
<tr><td>Modified Wobbe Index Range</td><td colspan="2">+5%</td><td colspan="2">–5%</td><td>See Notes 4,5</td></tr>
<tr><td>Superheat, °F</td><td colspan="2">–</td><td colspan="2">50</td><td>See Note 6</td></tr>
<tr><td>Flammability</td><td colspan="2">See Note 7</td><td colspan="2">>2.2:1</td><td>Rich to lean fuel to air ratio, volume basis
See Note 8</td></tr>
<tr><td>Gas Constituent Limits, % by volume:</td><td colspan="2"></td><td colspan="2"></td><td></td></tr>
<tr><td>Methane</td><td colspan="2">100</td><td colspan="2">85</td><td>% of reactant species</td></tr>
<tr><td>Ethane</td><td colspan="2">15</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Propane</td><td colspan="2">15</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Butane + Paraffine (C4+)</td><td colspan="2">5</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Hydrogen</td><td colspan="2">0</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Carbon Monoxide</td><td colspan="2">15</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Oxygen</td><td colspan="2">10</td><td colspan="2">0</td><td>% of reactant species</td></tr>
<tr><td>Carbon Dioxode</td><td colspan="2">15</td><td colspan="2">0</td><td>% total (reactants + inerts)</td></tr>
<tr><td>Nitrogen</td><td colspan="2">30</td><td colspan="2">0</td><td>% total (reactants + inerts)</td></tr>
<tr><td>Sulfur</td><td colspan="2">–</td><td colspan="2">–</td><td>See Note 9</td></tr>
<tr><td>Total Inerts (N_2 + CO_2+AR)</td><td colspan="2">30</td><td colspan="2">0</td><td></td></tr>
<tr><td>Aromatics (Benzene, Toluene etc.)</td><td colspan="2">Report</td><td colspan="2">0</td><td>See Note 10</td></tr>
<tr><td>Gas Fuel Supply Pressure</td><td colspan="2"></td><td colspan="2"></td><td>See Note 11</td></tr>
<tr><th>CONTAMINANTS
(See Notes 12,13)</th><th colspan="4">FUEL LIMITS
ppmw (See Note 14)</th><th>NOTES</th></tr>
<tr><td>Particulate</td><td>MS3000
MS5000</td><td>B/E Class</td><td>F Class</td><td>H Class</td><td>See Note 15</td></tr>
<tr><td>Total
Above 10 Microns</td><td>35
0.4</td><td>32
0.3</td><td>23
0.2</td><td>23
0.2</td><td></td></tr>
<tr><td>Trace Metals
Sodium plus potassium</td><td colspan="4">0.8</td><td>See Note 16</td></tr>
<tr><td>Liquids</td><td colspan="4">0</td><td>No Liquids allowed, see superheat requirements and Note 17</td></tr>
</table>

Notes:

1. All fuel properties must meet the requirements from ignition to base load unless otherwise stated.
2. Values and limits apply at the inlet of the gas fuel control module.
3. Heating value ranges shown are provided as guidelines. Specific fuel analysis must be furnished to GE for proper analysis. (Reference Section III-A)
4. See section III-B. for definition of Modified Wobbe Index Range.

ATTACHMENT SH-EU3-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

This attachment provides a general description of the water injection system's operation as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU3-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

GENERAL

The water injection system provides water to the combustion system of the gas turbine to limit the levels of nitrogen oxides (NOX) in the turbine exhaust. This limitation is required by strict local and federal regulations. The water injection system schedules water flow to the turbine as a function of total fuel flow, relative humidity, and ambient temperature. The required water/fuel ratio is established through field compliance testing of the individual turbine. A final control schedule based on these tests is programmed in the SPEEDTRONICE control, which then regulates the system. The water injection system consists of both on-base components and an off-base water injection skid. This skid is a factory assembled and enclosed package. It receives water from the customer's treatment facility, and delivers filtered water at the pressure and flow rate required to meet the applicable emissions requirement at that operating condition. The filtered water is introduced to the turbine combustion system through a water supply manifold. The manifold supplies water to each of the 14 combustors on the gas turbine. The manifold inlet connection is located on the turbine base. The water is injected through identical nozzles in each of the combustors. The following is a brief functional description of the system as well as a control and monitoring description. More detailed information on individual items is given in the manufacturer's literature (Equipment Publications).

FUNCTIONAL DESCRIPTION

The water injection system supplies treated and filtered water at the required flow rate and pressure to the combustion system of the gas turbine. Water enters the skid and passes through a strainer (FW1-2), which protects the system components from damage by foreign objects. A pressure switch (63WN-1) senses pressure upstream of the Pump. The SPEEDTRONICE control system will trip the pump motor if the pressure sensed by this switch is too low. This protects the pump from damage due to cavitation. An electric motor (88WN-1) drives the centrifugal water injection pump (PW1-1). The speed of the electric motor is controlled by a Variable Frequency Drive unit or VFD (97WN-1). The VFD modulates the frequency of the AC power supplied to the motor (88WN-1). By varying the frequency of the AC power, the pump speed can be precisely controlled. By varying the pump speed, the pump discharge pressure, and hence the discharge flow rate are controlled. The VFD controls the pump speed in response to a 4-20 mA

demand signal from the SPEEDTRONICE. A 0-10 V speed feedback signal (96WN-4) from the VFD is fed back to the SPEEDTRONICE for monitoring and fault detection purposes. A discharge pressure transmitter (96WP-1) is located downstream of the pump. The signal from this transmitter is fed back to the SPEEDTRONICE for monitoring and fault detection. The flow then passes through a high pressure filter assembly (FW1-1). The filter elements are contained in a high pressure filter housing, with a vent and drain. A differential pressure gauge indicates the pressure drop across the filter. A differential pressure switch (63WN-3) also senses the differential pressure across the filter, and signals an alarm in the SPEEDTRONICE control if the pressure differential exceeds the pressure specified in the device summary. Downstream of the filter, the flow is split into a main line to the turbine, and a recirculation line, which returns to the pump inlet upstream of the inlet strainer via the "cascade" recirculation orifice. The recirculation flow allows the pump to run in a stable and safe condition when there is little or no flow being delivered to the turbine. It is important that the pump is not run only on recirculation flow for an extended period of time. Extended running on pump recirculation only may cause overheating of the pump, or damage to the pump seals. The water flow in the main line next passes through a turbine flowmeter (FM1-1), with triple pick-ups, each with its own Flow Transmitter (96WF-1, 96WF-2, and 96WF-3). The flowmeter provides a signal to the SPEEDTRONICE control system. A strainer (FW1-3) is installed downstream of the flowmeters, to protect the other system components in the event of a flowmeter failure. Manually operated bypass/isolation valves, and a bypass piping loop is provided to allow the flowmeter to be isolated (e.g. for flushing) or to be removed for maintenance (if necessary). Downstream of the flowmeters, the flow passes through a water actuated stop valve (VS2-1), with solenoid control valve (20WN-1), which shuts off water flow in response to a command from the control system. Downstream of the stop valve is a manual isolation valve, followed by the skid discharge connection ("WJ2"). Interconnecting piping (provided by the customer) carries the water flow from the skid discharge to the manifold connection on the turbine base ("WI2"). The manifold distributes flow equally to fourteen flow proportioning valves (VWP1-1 to 14). These valves have a 15 psid (1.0 kg/cm2) cracking pressure, and provide a graduated flow restriction such that the flow resistance is relatively high at low flows. The purpose of the flow proportioning valves is to provide an even flow distribution at start-up and at low flows. The discharge from each of these valves is connected to tubing, which carries the flow of water to one of the combustors.

CONTROL AND MONITORING

Total water flow to the turbine is scheduled as a function of fuel flow to the turbine. A control schedule must be established during field compliance tests to meet emissions limits specified by the applicable local or federal standards. The compliance curve, determined as a result of these tests, is programmed into the SPEEDTRONICE control system. It is used as a reference for comparison to the actual water flow, in order to verify that emissions regulations are being met.

The electronic controllers (micro-computers R, S, and T) in the SPEEDTRONICE, control the flow of water in accordance with the control schedule and compliance control curve. The controllers generate a 4 to 20 mA demand signal to the Variable Frequency Drive, which accurately modulates pump speed to obtain the required flow. The control signal is generated in accordance with the control schedule, to achieve the required emissions levels at that particular operating condition. The skid flowmeter (FM1-1) generates a 4-20 mA output proportional to flow rate, which the SPEEDTRONICE uses in the flow control loop as a feedback signal.

ATTACHMENT SH-EU3-J3

DETAILED DESCRIPTION OF
CONTROL EQUIPMENT

FUEL GAS CONTROL SYSTEM (DLN_X 2.6)

This attachment provides a general description of Dry Low NO_X system's operation as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU3-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

FUEL GAS SYSTEM (DLN 2.6)

GENERAL

The Stop/Speed Ratio Valve (SRV) and the Gas Control Valves (GCVs) work in conjunction to regulate the total fuel flow delivered to the gas turbine. This arrangement uses four separate Gas Control Valves to control the distribution of the fuel flow to a multi-nozzle combustion system. (See Gas Fuel System schematic) The GCVs control the desired fuel flow in response to a control system fuel command, Fuel Stroke Reference (FSR). The response of the fuel flow to GCVs' commands is made predictable by maintaining a predetermined pressure upstream of the GCVs. The GCVs' upstream pressure, P2 , is controlled by modulating the SRV based on turbine speed as a percentage of full speed, TNH, and feedback from the P2 pressure transducers, 96FG-2A, B, and C. Refer to the Gas Fuel System schematic. In a Dry Low NOx 2.6 (DLN-2.6) combustion system there are four gas fuel system manifolds: Premix 1 (PM1), Premix 2 (PM2), Premix 3 (PM3), and Quarternary (Q). Each combustion chamber has a total of six fuel nozzles. The PM1 gas fuel delivery system consists of one diffusion type fuel nozzle for each combustion chamber. The PM2 gas fuel delivery system consists of two premix type fuel nozzles for each combustion chamber. The Quarternary gas fuel delivery system consists of injection pegs located in each combustion casing. The PM3 gas fuel delivery system consists of three premix type fuel nozzles for each combustion chamber. The GCVs regulate the percentage of the total fuel flow delivered to each of the gas fuel system manifolds.

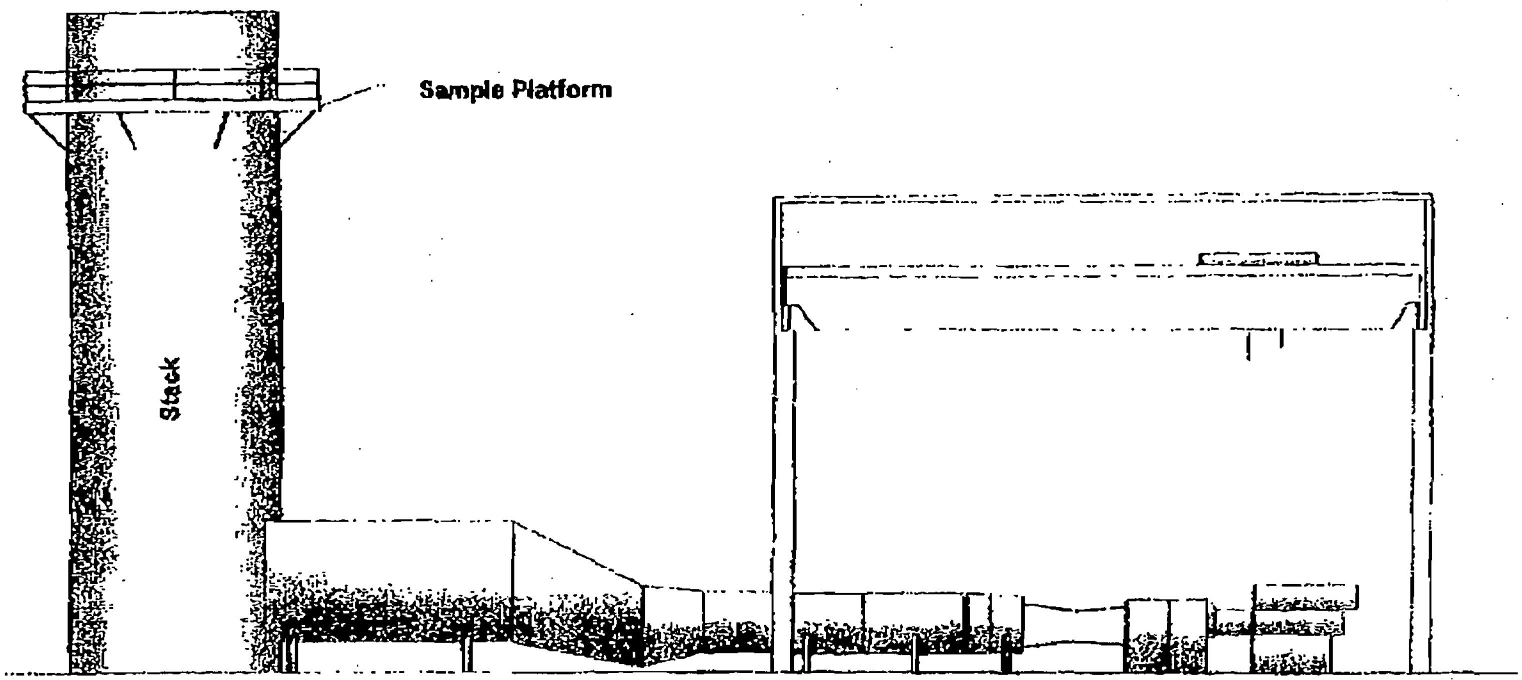
FUEL GAS CONTROL SYSTEM

The GCVs and SRV are actuated by hydraulic cylinders moving against spring loaded valve plugs. Three coil servo valves are driven by electrical signals from the control system to regulate the hydraulic fluid in the actuator cylinders. Redundant sensors in the form of Linear Variable Differential Transformers (LVDTs) mounted on each valve provide the control system with valve position feedback for closed loop position control. A functional explanation of each part or subsystem is contained in subsequent paragraphs. For more detail on the electro-hydraulic circuits see the SPEEDTRONIC System text, Gas Fuel system schematics, and Control Sequence Programs furnished to the site.

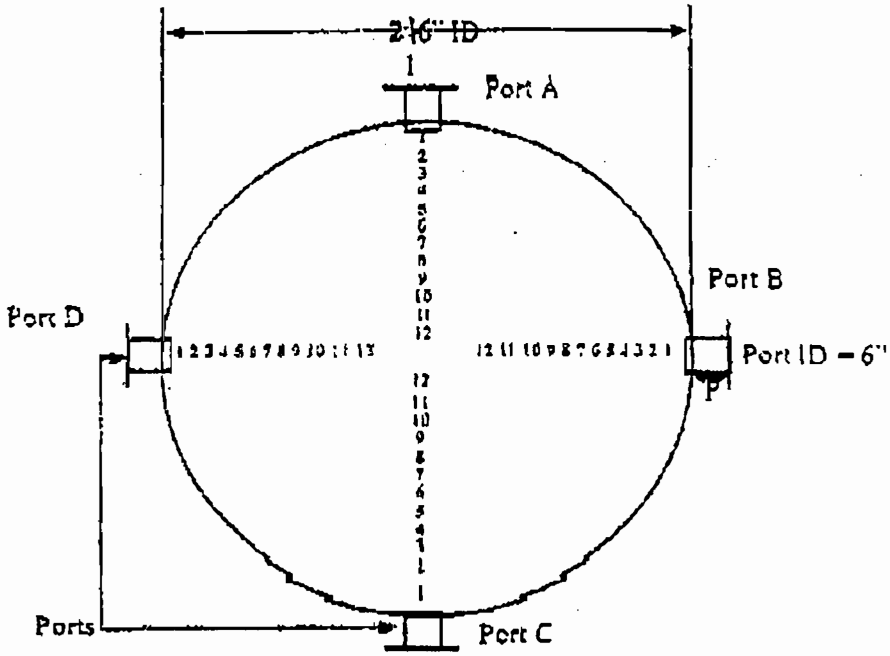
Gas Control Valves

The plugs in the GCVs are contoured to provide the proper flow area in relation to valve stroke. The combined position of the control valves is intended to be proportional to FSR. The GCVs use a skirted valve disc and venturi seat to obtain adequate pressure recovery. High pressure recovery occurs at valve pressure ratios substantially less than the critical pressure ratio. The result is that the flow through the GCVs is independent of the pressure drop across the valves and is a function of valve inlet pressure, P2, and valve area only. The control system's fuel command, FSR, is the percentage of maximum fuel flow required by the control system to maintain either speed, load, or another setpoint. FSR is broken down into two parts which make up the fuel split setpoint, FSR1 and FSR2. FSR1 is the percentage of maximum fuel flow required from the Liquid Fuel System and FSR2 is the percentage of maximum fuel flow required from the Gas Fuel System. FSR2 is also broken down into four parts, FSRPM1, FSRPM2, FSRPM3 and FSRQT. FSRPM1 is the percentage of FSR2 controlling the GCV1 gas fuel valve. FSRPM2 is the percentage of FSR2 to be directed to the GCV2 gas fuel valves, and so on. FSRPM1 is used as a reference to a servo amplifier, which drives the coils of GCV #1. FSRPM2 is used to drive the coils of GCV #2, and so on.

ATTACHMENT SH-EU3-J4
DESCRIPTION OF STACK SAMPLING FACILITIES



GENERAL ARRANGEMENT



Traverse Point	% of Diameter from near wall	Distance from Inner Wall (inches)
1	1.1	2.1
2	3.2	6.9
3	5.5	11.9
4	7.9	17.1
5	10.5	22.7
6	13.2	28.5
7	16.1	34.8
8	19.4	41.9
9	23.0	49.7
10	27.2	58.8
11	32.3	69.8
12	39.8	86.0

Figure - . Traverse point sampling CEMS

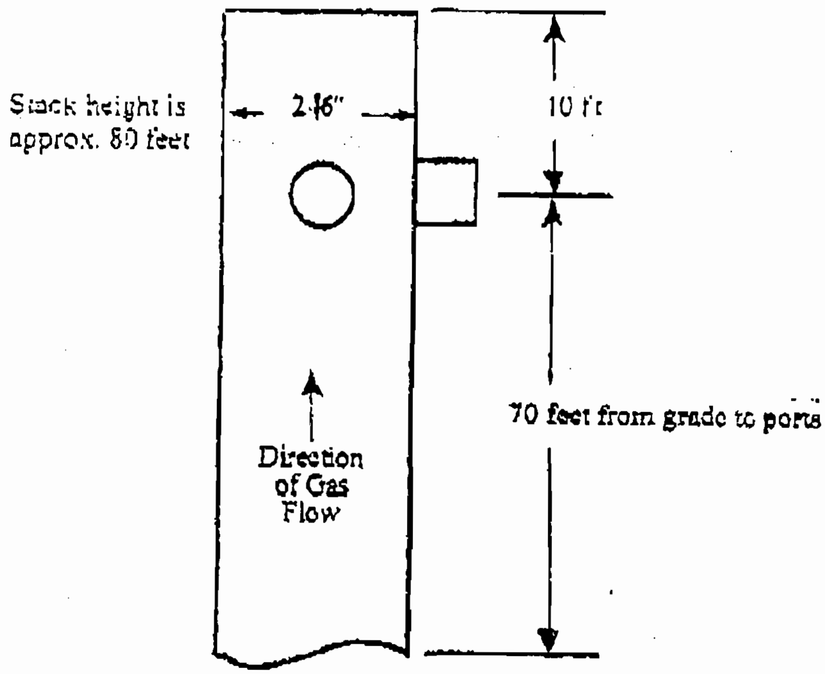


Figure - . Stack sample location.

ATTACHMENT SH-EU3-J5
COMPLIANCE TEST REPORT

ATTACHMENT SH-EU3-J5

COMPLIANCE TEST REPORT

Emission Unit 3 was tested for initial compliance with all applicable emission limits set forth in Air Construction Permit PSD-FL-280 (1010373-001-AC) for both natural gas and fuel oil operation at 100 percent load. The compliance tests for natural gas operation were performed on February 20, 2002. The compliance tests for fuel oil operation were performed on February 18, 2002. The compliance test report will be submitted within 45 days of February 18, 2002, which corresponds to April 4, 2002.

ATTACHMENT SH-EU3-J6

PROCEDURES FOR STARTUP/SHUTDOWN

This attachment provides a general description of the startup and shutdown procedures as recommended by General Electric. Actual operation will depend on operating conditions as determined by the facility.

OPS-023 COMBUSTION TURBINE STARTUP

Shady Hills, FL
GE Contractual Services
Effective Date: Pending

Number: OPS-023
Attachment SH-EU3-J6a.doc

I. **SCOPE**

A. The purpose of this procedure is to provide safe means of Startup of the Gas Turbine Generators.

II. **DEFINITIONS**

A. None.

III. **RESPONSIBILITIES**

A. Facility Management

1. To revise this procedure when new safety measures and operating techniques or technologies become available.

B. Employee

1. To implement this operation by utilizing verbatim compliance of this procedure.

2. To use this procedure in parallel with all approved safety procedures.

3. To notify supervision when any unsafe or abnormal condition presents itself.

IV. **GUIDELINES**

A. Start required BOP Equipment

1. Start closed cooling water in accordance with OPS-031.

2. Start raw water for evap coolers in accordance with OPS-028.

3. Verify fuel systems are aligned in accordance with VLU's.

4. Start demin transfer pump in accordance with OPS-050.

5. Verify Compressed air system is online in accordance with OPS-037.

6. Verify gas heater is aligned and ready for operation in accordance with OPS-035.

7. Refer to OPS-044 for instructions on synchronizing.

B. Select "Main" display from the demand display.

1. HMI: Shutdown Status
Off Cool down or ON Cool down
Off

C. Select "Auto synchronize" ON

D. Select "Water Injection" ON

E. Select fuel to be used for start-up

F. Select "Auto" or "Remote" Depending on start location then "Execute".

1. "HMI: Startup Status
Ready to Start
Auto

G. Select "Start" and " Execute":

1. Unit Auxiliaries will be started lube oil flow will be established.

a. HMI: Seq in progress

2. When permissives are satisfied (L4) will be satisfied.

a. HMI: Startup Status
Starting
Auto; Start

3. When inot in cool down turning gear will engage, when unit realized approx. 6 rpm starting device will be energized and accelerate the unit.

a. HMI: Startup Status Crank

4. When unit reaches 15% speed "14 HM" will appear on HMI at this time unit will purge for 5 minutes.

5. FSR will be set to firing valve. Ignition sequence is initiated.

a. HMI: Startup Status/Firing

6. Flame established HMI; display will indicate flame in those combustors with flame detectors.

7. Select "Base Load"

8. FSR set back to warm-up valve.

a. HMI: Startup Status/Warming up

NOTE

If flame goes out during the 60-second firing period, FSR will be reset to firing valve. At this time you may shut the unit down or attempt to fire again to fire again select CRANK on main display.

9. At the end of the warm up period, with flame established, FSR will increase.

a. HMI: Start-up Status/Accelerating 50% speed "14HA" will be displayed on HMI.

10. Turbine will continue to accelerate, at 85-90% starting device will disengage and shutdown.

    a. HMI: Startup control to speed control at approx 60% speed.

11. When turbine reaches operating speed "14HS" will be on HMI, field flashing is then terminated, if software switch (43S) is in off and remote is not selected on HMI.

    a. HMI: Run Status
       Full Speed No Load
       Auto; Start

12. If 43S is in auto or remote on HMI; Automatic Sync is initiated.

    a. HMI: Synchronizing

H. Normal Load Operation: Refer to OPS-043

NOTE:
Operator should monitor mode changes for proper DLN operation and indication of flame. Also monitor vibration screen for any extreme changes.

V. TRAINING

A. Complete Control Room Operator Qualifications.

VI. REFERENCES

A. GEK 107357 (GE Operations and Maintenance Manuel)
B. OPS-043
C. OPS-044

VII. APPENDIX

A. None

OPS-024 COMBUSTION TURBINE STARTUP

Shady Hills, FL
GE Contractual Services
Effective Date: Pending

Number: OPS-024
Attachment SH-EU3-J6b.doc

I. SCOPE

A. The purpose of this procedure is to provide safe means of shutting down the Gas Turbine Generators.

II. DEFINITIONS

A. None

III. RESPONSIBILITIES

A. Facility Management

1. To revise this procedure when new safety measures and operating techniques or technologies become available.

B. Employee

1. To implement this operation by utilizing verbatim compliance of this procedure.

2. To use this procedure in parallel with all approved safety procedures.

3. To notify supervision when any unsafe or abnormal condition presents itself.

IV. GUIDELINES

A. Select STOP on the <I> /HMI Main Display.

1. The unit will automatically unload, reduce speed, and chop fuel at part speed, and initation of cooldown sequence as unit coasts to a stop.

B. Immediately following shutdown verify unit is on turning gear to ensure minimum protection against rubs and unbalance on subsequent starting attempt. G.E. recommends 48 hrs, prior to taking off cool down.

C. Shut down and isolate associated BOP equipment in accordance with procedures.

D. If this is the last unit to be shutdown refer to OPS-022 for supply systems to be shut down.

E. Upon completion of supply systems shutdown perform the following.

1. Walk unit down and inspect for leaks and any broken equipment.
2. Take a set of logs.
3. Verify unit is ready to start at HMI.
4. Clear any alarms, and investigate problems and correct.

V. TRAINING

A. Complete SR. Operations qualification.

VI. REFERENCES

A. GE Operations and Maintenance Manuals

ATTACHMENT SH-EU3-J7

OPERATION AND MAINTENANCE PLAN
FUEL GAS SYSTEM

This attachment provides a general description of operation and maintenance procedures as recommended by General Electric. Actual operation and maintenance plans will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU3-J7

OPERATION AND MAINTENANCE PLAN

FUEL GAS SYSTEM

GENERAL

The dry low NOx 2.6 (DLN-2.6) control system regulates the distribution of fuel delivered to a rnulti-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion chamber fuel nozzle assembly is calculated to maintain unit load and fuel split for optimal turbine emissions.

GAS FUEL SYSTEM

The DLN 2.6 Combustion system consists of six fuel nozzles per combustion can, each operating us a fully premixed combustor, five located radially, one located in the center. The center nozzle, identified as PM 1, (PreMix 1), two outer nozzles located adjacent to the crossfire tubes, identified as PM2, (PreMix 2), and the remaining three outer nozzles, identified as PM3, (PreMix 3). Another fuel passage, located in the airflow upstream of the premix nozzles, circumferentially around the combustion can, is identified as the quaternary fuel pegs, The fuel flow to the six fuel nozzles and quaternary pegs are controlled by four independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one, (PM1), gas control valve two (PM2), gas control valve three, (PM3), and gas control valve four, (Quat). The stop/ratio valve (SRV) is designed to maintain a predetermined pressure, (P2), at the inlet of the gas control valves. Gas control valves one through four, (GCVI-4), regulate the desired gas fuel flow delivered to the turbine in response to the command signal FSR, (Fuel Stroke Reference), from the SPEEDTRONIC panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. This flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software. The stop ratio valve and gas control valves are monitored for their ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to Warn the operator. If the condition persists for an extended amount of time, the turbine will be tripped and another alarm will annunciate the trip.

CHAMBER ARRANGEMENT

The 7F machine employs 14 combustors while the 9F employs 18 similar but slightly larger combustors. For each machine there are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent combustors. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi-nozzle cap assembly, liner assembly, and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion can, porting fuel to casing injection pegs located radially around the casing.

ATTACHMENT SH-EU3-J7

OPERATION AND MAINTENANCE PLAN
LIQUID FUEL SYSTEM

This attachment provides a general description of operation and maintenance procedures as recommended by General Electric. Actual operation and maintenance plans will depend on operating conditions as determined by the facility.

ATTACHMENT SH-EU3-J7

OPERATION AND MAINTENANCE PLAN

LIQUID FUEL SYSTEM

GENERAL

The liquid fuel (distillate oil) system filters, pressurizes, controls, and equally distributes fuel flow to the fourteen turbine combustion chambers. Flow is regulated by controlling the position of 3-way valve VC3-1. The entire liquid fuel system must be pressurized, with all valves in the open position, before starting the gas turbine. The liquid fuel system should be operated for a minimum of one half hour every week to prevent binding of the components. This is best achieved by operation of the turbine on liquid fuel for a minimum of one half hour per week with either 100% fuel oil or fuel gas mixed mode with fuel oil. The fuel system is comprised of the following major components:

1. Duplex low-pressure fuel filter FF1-l, -2 with transfer valve VM5-l and thermal pressure relief valves VR41-1, -2.
2. Fuel pump PF1-l with driving motor 88FP-1 and motor heater 23FP-l and discharge pressure relief valve VR4-1.
3. Fuel flow control valve VC3-1.
4. Fuel stop valve VS1-1.
5. Fuel flow divider FD1-1.
6. Nozzle pressure selector valve VH17-l.
7. Check valves VCKI-l through 14.
8. Fuel nozzle assemblies.

Except for the check valves and fuel nozzles all components are mounted in the off-base liquid, fuel/atomizing air module.

FUNCTIONAL DESCRIPTION

Duplex Low-Pressure Fuel Filter

Fuel oil forwarded to the liquid fuel module within specified pressure and temperature ranges enters the low pressure filter FF1-l or FFI-2 via transfer valve VM5-1 prior to entering the fuel pumps. The low-pressure filter consists of multiple five-micron synthetic elements with oversize contamination capacity. These elements retain contaminants, which could damage downstream components. The filter vessels are protected from thermal overpressure by relief valves

VR41-1, -2. Differential pressure switch 63LF-5 gives a signal when the pressure drop across the filter reaches 15 psid (103 kPad). The ditty filter should then be serviced by replacing the dirty elements with clean ones.

Fuel Pump

Fuel pump PFI-1 is of the axial flow, positive displacement, rotary, screw type with one power rotor (driven screw) and two intermeshing idler rotors. The single ball bearing positions the power rotor for proper operation of the mechanical seal. The bearing is permanently '"grease packed and external to the pumped fuel. The motor driven fuel pump 88FP/PFI-1 is rated at one hundred percent capacity of the maximum turbine fuel requirement. The pump motor is equipped with an integral heater 23FP-l. The pump is protected from insufficient suction pressure by permissive-to-start pressure switch 63FL.2. During normal operation this switch functions as a low-pressure alarm. The fuel system is protected from excessive pressure by pump discharge relief valve VR4-1 that relieves pressure back to filter inlet.

Fuel Flow Control Valve

Pump discharge flow is modulated by the servocontrolled three-way control valve assembly VC3-1. Components of this assembly include the valve body, electrohydraulic servovalve 65FP-1, hydraulic oil filter FH3-1 and the cylinder. The valve controls the flow to the turbine by throttling the main port while opening the bypass port, returning the bypass flow to pump suction.

Liquid Fuel Stop Valve

Hydraulically operated three-way fuel oil stop valve VS1-1 shuts off the supply of fuel to the turbine during normal or emergency shutdowns. During normal turbine operation, the valve is held open (bypass closed) by high-pressure hydraulic oil that passes through a hydraulic trip relay (dump) valve VH4-1. This dump valve, located between the hydraulic supply and the stop valve hydraulic cylinder, is hydraulically operated by trip oil acting through solenoid valve 20FL-l. During a normal shutdown or emergency trip, low trip oil pressure will cause valve VH4-1 to shift position, dumping high-pressure hydraulic oil from the stop valve actuating cylinder, allowing the stop valve spring to close the valve. During an electrical trip, solenoid valve 20FL-l causes the dump valve to shift with the same results as above. The stop valve will be fully closed within 0.5 second of the trip signal. Limit switch 33FL-l signals stop valve closed position.

Flow Divider

Flow divider FD1-1 equally distributes filtered fuel to the 14 combustors. It is a continuous flow, free wheeling device consisting of fourteen gear pump elements in a circular or linear arrangement having a common inlet with a single timing gear or shaft. This timing (sun) gear or shaft maintains the speed of each flow element synchronous with all the other elements.

The speed of each flow divider gear element is directly proportional to the total flow through the flow divider. Magnetic pickup assemblies 77FD-l, -2 and -3, fitted to the flow divider, produce a flow feedback signal at a frequency proportional to the fuel delivered to thc combustion chambers. This signal is fed to the SPEEDTRONICE control panel where it is used in the fuel control system.

Pressure Selector Valve

An eighteen position pressure selector valve VH17-l allows monitoring of individually selected line pressures on a local gauge. These include: anyone of the fourteen combustor fuel lines; pump discharge pressure; and flow divider inlet pressure.

Check Valves

Check valves VCKI-l through 14 isolate the fuel nozzles during shutdown periods to prevent line drainage and flow communication between combustors.

ATTACHMENT SH-EU3-J14
COMPLIANCE ASSURANCE MONITORING PLAN

ATTACHMENT SH-EU3-J14

COMPLIANCE ASSURANCE MONITORING PLAN

The only control device for the CT is water injection for NOx control. Continuous Emission Monitors (CEMS) monitor NOx, therefore the Compliance Assurance Monitoring Plan is not applicable.

ATTACHMENT SH-EU3-J15

ACID RAIN PART APPLICATION

Golder Associates Inc.

5100 West Lemon Street, Suite 114
Tampa, FL USA 33609
Telephone (813) 287-1717
Fax (813) 287-1716

Golder Associates

November 12, 2001

Project No.013-9517

Mr. Bob Miller
US EPA Clean Air Markets
Mail Code 6204J
501 3rd Street, NW
Washington, DC 20001

RE: Acid Rain Permit
Shady Hills Power Company, L.L.C.
Shady Hills Generating Station
Pasco County, Florida

Dear Mr. Miller:

Enclosed is notification of a change in the designated representative and alternate designated representative for the above referenced project. Please find The Certificate of Representation [EPA Form 7610-1(rev.4-98)], which identifies Mr. James M. Packer, Director of Operations and Mr. John E. Dorsett, Vice President of Business Development/Operations, Shady Hills Power Company, L.L.C. as the designated representative and alternate designated representative, respectively.

Shady Hills Power Company, L.L.C. and Golder Associates Inc. appreciate your assistance in processing the above referenced information. If you have any questions or need additional information, please contact me at (813) 287-1717.

Very truly yours,

GOLDER ASSOCIATES INC.

Manitia Moultrie
Manitia Moultrie
Senior Project Manager

MM/AT/nd

Enclosures

cc: Mr. Scott Sheplak, Florida Department of Environmental Protection
Mr. Jimmy Packer, Mirant Corporation
Mr. Chuck Jordan, Mirant Corporation
Mr. Glenn Keeling, Mirant Corporation

H:\GolderVol1\PROJECTS\2001proj\013-9517 Mirant - Shady Hills Compliance\0100 - Project Management\REP TRANSFER 10-01\transfer of authorized rep-Miller.doc

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Certificate of Representation

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
Shady Hills Generating Station	FL	55414

STEP 2
Enter requested information for the designated representative.

Name: James M. Packer, Shady Hills Power Company, L.L.C.	
Address: 1155 Perimeter Center West Atlanta, Georgia 30338-5416	
Phone Number: (678) 579-7962	Fax Number: (678) 579-7358
E-mail address (if available): jimmy.packer@mirant.com	

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

Name: John E. Dorsett	
Phone Number: (678) 579-7349	Fax Number: (678) 579-7358
E-mail address (if available): eddie.dorsett@mirant.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 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.

Shady Hills Generating Station
Plant Name (from Step 1)

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.

James M. Packer Signature (designated representative)	11-07-01 Date
Signature (alternate designated representative)	11-08-01 Date

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.

Shady Hills Power Company, L.L.C. Name					☒ Owner ☐ Operator	
CT1 ID#	CT2 ID#	CT3 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#

Name					☐ Owner ☐ Operator	
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

EL PASO
MERCHANT ENERGY

November 21, 2000

Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399
MS 5505

Attention: Mr. Scott Sheplak, P.E.

RE: Acid Rain Program, Phase II Permit Application
Shady Hills Power Company, L.L.C. – Shady Hills Generating Station

Dear Mr. Sheplak:

Please find attached a Phase II Permit Application for the Shady Hills Generating Station located in Pasco County, Florida that is owned and operated by the Shady Hills Power Company, L.L.C. With one exception, this certificate is submitted in accordance with the provisions of Title 40, Parts 72.30 and 72.31 of the Code of Federal Regulations applicable to facilities regulated by the Acid Rain Program. This exception is in regard to the date of submission described in the regulation as the later of 24 months prior to January 1, 2000 or 24 months prior to the unit commencing operation. Due to the short period of time before the anticipated start of operation for the facility (January 2002), Shady Hills Power Company, L.L.C. was unable to meet this deadline.

Also, please find attached a copy of the Certificate of Representation form as the original was sent to the US EPA.

If you have any questions concerning the attached information, please call me at the phone number provided.

Sincerely,
Shady Hills Power Company, L.L.C.

John J. O'Rourke
V. P. and Managing Director
Venture Management

Enclosures

COPY

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Phase II Permit Application

Page 1

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

This submission is: ■ New ☐ Revised

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

Plant Name Shady Hills Generating Station State FL ORIS Code 55414

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 ~~w units, enter the requested information in columns d and e.

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
GT 101	Yes		Jan 29, 2002	April 30, 2002
GT 201	Yes		Jan 29, 2002	April , 2002
GT 301	Yes		Mar 1, 2002	Jun 1, 2002

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.

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Shady Hills Generating Station

Plant Name (from Step 1)

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

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Shady Hills Generating Station

Plant Name (from Step 1)

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 Mr. John O'Rourke	
Signature J. O'Rourke	11/27/00 Date

STEP 5 (optional)
Enter the source AIRS
FINDS identification

AIRS	
FINDS	

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).

[X] 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.

[X] 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):

Unreg. Emissions Activities - 1 Tank 2.8 M gallons

4. Emissions Unit Identification Number: [ ] No ID
ID: **004** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**April 2002**	**49**	[ ]

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

This emission unit information section addresses one 2.8 million-gallon. NSPS Subpart Kb recordkeeping requirements are applicable; there is no emission limiting or work practice standards.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):
2. Control Device or Method Code(s):

Emissions Unit Details

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

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60 Subpart Kb	

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Oil/Diesel**		
2. Source Classification Code (SCC): **A2505030090**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **41,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment (limit to 200 characters): **Annual rate combined for the fuel oil tank based on inputs to CTs; 18,560 Btu/lb (LHV); and 7.1 lb/gal at 59°F.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			NS