TITLE V AIR OPERATION PERMIT RENEWAL APPLICATION

DeSoto County Energy Park
Arcadia, DeSoto County

Permit Application

Prepared For: DeSoto County Generating Company, LLC
3800 Northeast Roan Street
Arcadia, FL 34266

Submitted By: Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA

Distribution: 4 copies – FDEP
2 copies – DeSoto County Generating Company, LLC
1 copy – Golder Associates Inc.

May 2012 123-87545

Golder Associates

APPLICATION FOR AIR PERMIT

LONG FORM

Department of Environmental Protection

RECEIVED
MAY 21 2012
DIVISION OF AIR RESOURCE MANAGEMENT

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **DeSoto County Generating Company, LLC**	
2. Site Name: **DeSoto County Energy Park**	
3. Facility Identification Number: **0270016**	
4. Facility Location... Street Address or Other Locator: **3800 Northeast Roan Street** City: **Arcadia** County: **DeSoto** Zip Code: **34266**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Scott Weis, Senior EHS Specialist**
2. Application Contact Mailing Address... Organization/Firm: **LS Power** Street Address: **400 Chesterfield Center, Suite 110** City: **St. Louis** State: **MO** Zip Code: **63017**
3. Application Contact Telephone Numbers... Telephone: **(314) 795-3037** ext. Fax: **(636) 532-2250**
4. Application Contact E-mail Address: **sweis@lspower.com**

Application Processing Information (DEP Use) 2012

1. Date of Receipt of Application: 5-22-	3. PSD Number (if applicable):
2. Project Number(s): 0270016-009-AV	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

- ☐ Air construction permit.
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- ☐ Initial Title V air operation permit.
- ☐ Title V air operation permit revision.
- ☒ Title V air operation permit renewal.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- ☐ Air construction permit and Title V permit revision, incorporating the proposed project.
- ☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- ☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

The purpose of this application is to renew Title V Air Operation Permit No. 0270016-007-AV, which expires on December 31, 2012.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	One Nominal 170 MW Simple-Cycle Combustion Turbine	AF2B	N/A
002	One Nominal 170 MW Simple-Cycle Combustion Turbine	AF2B	N/A

Application Processing Fee

Check one: ☐ Attached - Amount: $_______________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name :
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3.	Owner/Authorized Representative Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4.	Owner/Authorized Representative E-mail Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name: **Dale Gray**	
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☒ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source or CAIR source.	
3. Application Responsible Official Mailing Address... Organization/Firm: **DeSoto County Generating Company, LLC** Street Address: **3800 Northeast Roan Street** City: **Arcadia** State: **FL** Zip Code: **34266**	
4. Application Responsible Official Telephone Numbers... Telephone: **(650) 515-5347** ext. Fax: **(636) 532-2250**	
5. Application Responsible Official E-mail Address: **dgray@lspower.com**	
6. Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. Dale Gray 5-15-2012 Signature Date	

APPLICATION INFORMATION

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: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**	
3. Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **21156** Fax: **(352) 336-6603**	
4. Professional Engineer E-mail Address: **ken_kosky@golder.com**	

5. 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.

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

(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal 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.

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

Kennard F. Kosky 5/17/12

Signature Date

(seal)

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **419.75** North (km) **3011.5**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/13/30** Longitude (DD/MM/SS) **81/48/42**	
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 :			

Facility Contact

1. Facility Contact Name: **Bob Renaud, Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **DeSoto County Generating Company, LLC** Street Address: **3800 Northeast Roan Street** City: **Arcadia** State: **FL** Zip Code: **34266**
3. Facility Contact Telephone Numbers: Telephone: **(863) 884-9604** ext. Fax: **(863) 884-9122**
4. Facility Contact E-mail Address: **brenaud@desotogeneration.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4. Facility Primary Responsible Official E-mail Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Simple-cycle combustion turbine Units 1 and 2 are subject to New Source Performance Standards (NSPS) – 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines.**	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM – Particulate Matter Total	**B**	**N**
PM10 – Particulate Matter	**B**	**N**
VOC – Volatile Organic Compounds	**B**	**N**
CO - Carbon Monoxide	**A**	**N**
NOx - Nitrogen Oxides	**A**	**N**
SO2 – Sulfur Dioxide	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: DCEP-FI-C1 ☐ Previously Submitted, Date:__________
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: See EU sections ☐ Previously Submitted, Date:__________
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: DCEP-FI-C3 ☐ Previously Submitted, Date:__________

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☐ Attached, Document ID:__________
3. Rule Applicability Analysis: ☐ Attached, Document ID:__________
4. List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☐ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities: (Required for initial/renewal applications only) ☒ Attached, Document ID: **DCEP-FI-CV1** ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☒ Attached, Document ID: **DCEP-FI-CV2** ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☒ Attached, Document ID: **DCEP-FI-CV3** Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☒ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☒ Attached, Document ID: **DCEP-FI-CV6** ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: 09/17/2007
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

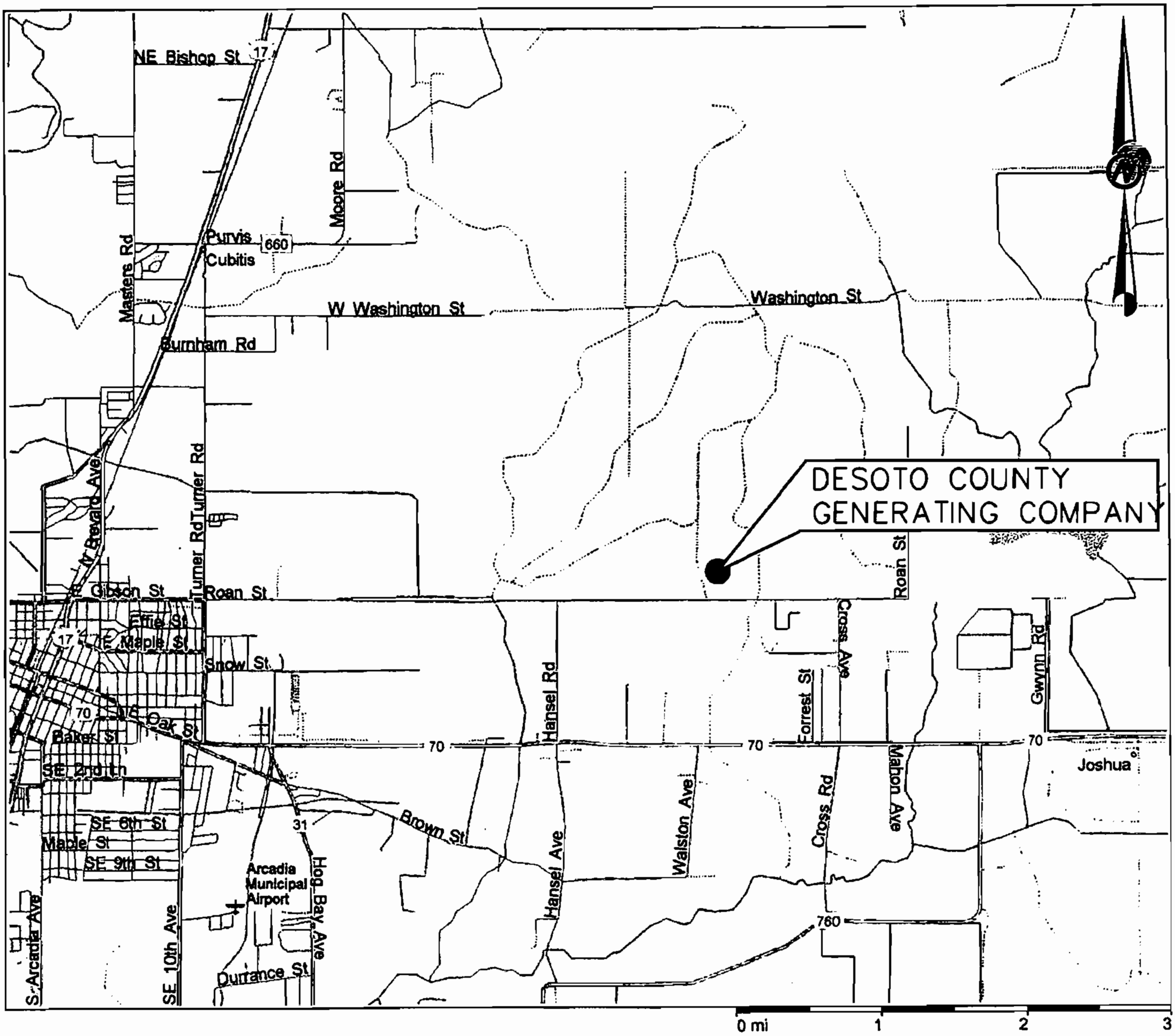
   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: 04/29/2008
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

ATTACHMENT DCEP-FI-C1

FACILITY PLOT PLAN



REFERENCES

1.) MAP TAKEN FROM MICROSOFT STREETS & TRIPS.

Golder Associates
Philadelphia USA

NJ Authorization #24GA28029100

SCALE	AS SHOWN
DATE	02/09/06
DESIGN	EM
CADD	AM
CHECK	RW
REVIEW	

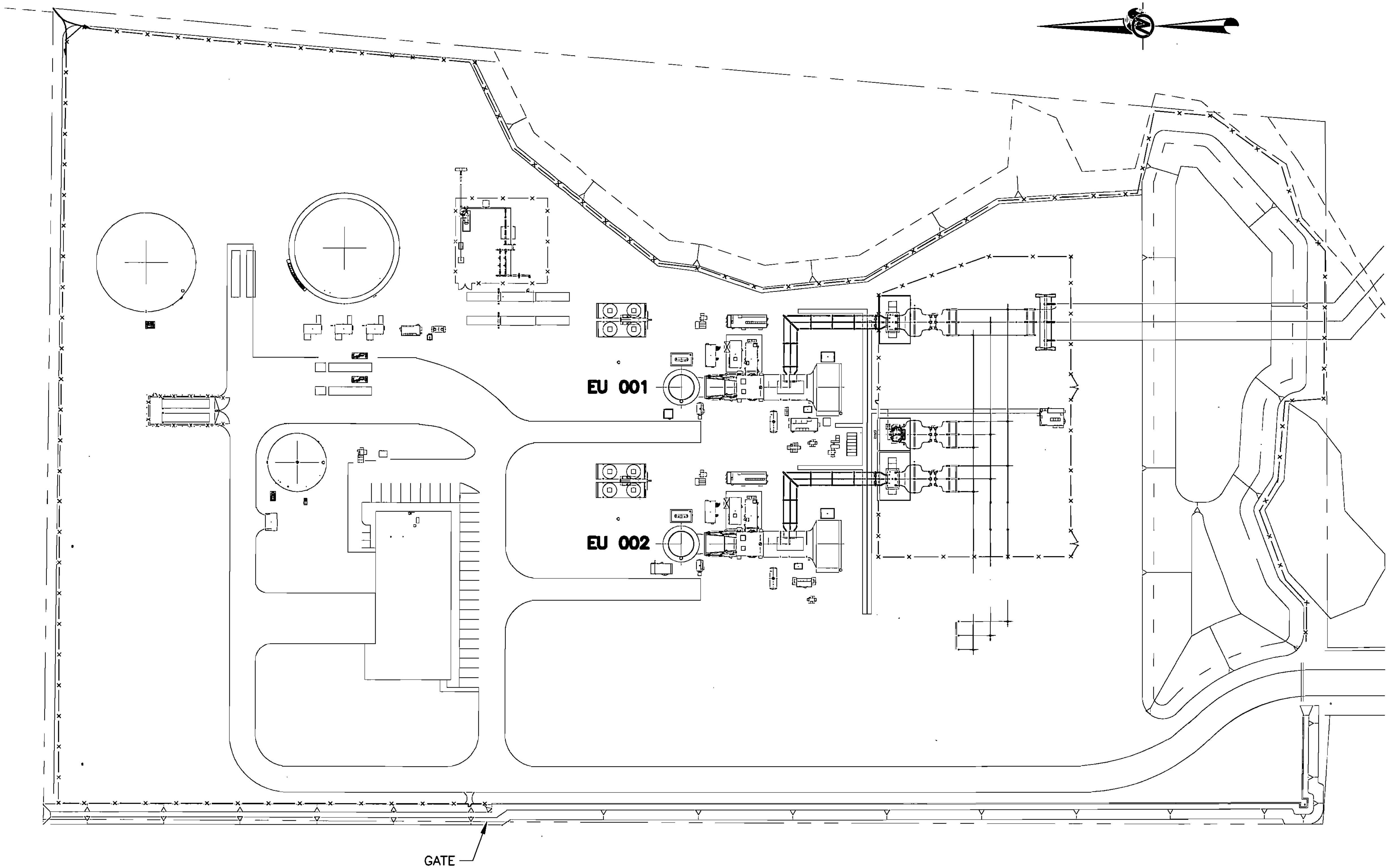
FILE No. 0639513A001

PROJECT No. 063-9513 REV. 0

Attachment DCEP-FI-C1a

Site Location Map

Drawing file: 06395 3A001.dwg Mar 02, 2006 - 3:02pm



NOTES

1.) EQUIPMENT SHOWN & NOT IDENTIFIED IS COMMON TO EACH UNIT.

REFERENCES

1.) MAP TAKEN FROM DIGITAL CAD FILE DESO-1-DW-3101-R2.DWG, TITLED "GENERAL ARRANGEMENT PLAN & LEGEND", PROVIDED BY CAREBA POWER ENGINEERS, LLC.

Golder Associates		SCALE	N.T.S	TITLE	
		DATE	05/17/2012	**FACILITY PLOT PLAN**	
		DESIGN	JDG		
		CADD	JDG		
FILE No.	123-87545A001	CHECK	SKM		
PROJECT No.	123-87545 REV. 0	REVIEW	SKM	DESOTO ENERGY PARK	ATTACHMENT DCEP-FI-C1B

Drawing file: 123-87545A001.dwg May 17, 2012 - 4:22pm

ATTACHMENT DCEP-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF
UNCONFINED PARTICULATE MATTER

ATTACHMENT DCEP-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Operational measures as applicable to the facility and consistent with Rule 62-296.320(4)(c)2, F.A.C., are undertaken to minimize unconfined particulate matter emissions.

Reasonable precautions in accordance with Rule 62-296.320(4)(c)2, F.A.C., are:

a. Paving and maintenance of roads, parking areas and yards.
b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.
e. Landscaping or planting of vegetation.
f. Use of hoods, fans, filters, and similar equipment to contain, capture, and/or vent particulate matter.
g. Confining abrasive blasting where possible.
h. Enclosure or covering of conveyor systems.
i. Posting and enforcing a speed limit for vehicles traveling on roadways on site.

ATTACHMENT DCEP-FI-CV1

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT DCEP-FI-CV1

LIST OF INSIGNIFICANT ACTIVITIES

The following emission units and/or activities at the DCEP are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.:

1. Operation of a CO_2 based fire protection system to be used in case of emergency fire in or near the combustion turbines.
2. Operation of an electric based fire protection system for the building. The unit also contains a small space heater.
3. Operation of a 13.5 MMBtu/hr (HHV) indirect fired fuel gas heater to prevent natural gas from freezing.
4. Storage and handling operations for lube, transformer, and fuel oil.
5. Miscellaneous maintenance and cleaning and painting of the building including the control room, maintenance shop, storage warehouse, and offices and their contents.
6. Miscellaneous heaters.
7. Miscellaneous general-purpose internal combustion engines for routine facility maintenance and/or equipment malfunctions.
8. Surface Coating operations using VOCs.
9. Water Analysis tasks to ensure proper operation of the water injection system and the combustion turbine cooling processes.
10. Storm water retention basin maintenance.
11. One 1.5 million gallon distillate fuel oil storage tank.
12. Parts washers.

ATTACHMENT DCEP-FI-CV2

IDENTIFICATION OF APPLICABLE REQUIREMENTS

ATTACHMENT DCEP-FI-CV2

IDENTIFICATION OF APPLICABLE REQUIREMENTS

TITLE V CORE LIST

Effective: 03/01/02

(Updated based on current version of FDEP Air Rules)

[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 60, Subpart GG: Standards of Performance for Stationary gas turbines.

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.
40 CFR 98, Subpart A: Mandatory Reporting of Greenhouse Gases.
40 CFR 98, Subpart C: General Stationary Combustion Sources.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 03-16-08

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.: Transferability of Definitions.
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 03-28-12

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, F.A.C.: Emissions Computation and Reporting.
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 03-28-12

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 02-16-12

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 02-16-12

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 02-16-12

62-297.310, F.A.C.: General Test Requirements.
62-297.310(4), F.A.C.: Applicable Test Procedures.
62-297.310(7), F.A.C.: Frequency of Compliance Tests.
62-297.310(6), F.A.C.: Repaired Stack Sampling Facilities.
62-297.310(5), F.A.C.: Determination of Process Variables.
62-297.510(8), 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 10-06-08
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 10-12-08
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

ATTACHMENT DCEP-FI-CV3

COMPLIANCE REPORT AND PLAN

ATTACHMENT DCEP-FI-CV3
COMPLIANCE REPORT

DeSoto County Generating Company, LLC certifies that the DeSoto County Energy Park located in Arcadia, DeSoto County, Florida, as of the date of this application, is in compliance with each applicable requirement addressed in this Title V air operation permit renewal application.

I, the undersigned, am the responsible official as designed in Chapter 62-213, 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.

Compliance statements for this facility will be submitted on an annual basis to FDEP, on or before March 1 of each year.

Signature, Responsible Official

DALE GRAY

5-15-2012

Date

ATTACHMENT DCEP-FI-CV6

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

ATTACHMENT DCEP-FI-CV6
REQUESTED ADMINISTRATIVE CHANGES

DeSoto County Generating Company, LLC requests the following changes to the Title V permit for the DeSoto County Energy Park (DCEP) facility.

Section III, Subsection A, Specific Condition A.2: Permitted Capacity

Specific Condition A.2 of the current Title V permit includes nominal heat input values of each turbine of 1,612 million British thermal units per hour (MMBtu/hr) for natural gas-firing and 1,806 MMBtu/hr for fuel oil firing at 59°F ambient temperature, 60 percent relative humidity, 100 percent load, and 14.7 pounds per square inch (psi) pressure. Condition A.2 also states that these nominal heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. DCEP requests the addition of a permitting note stating that the nominal heat input values are not permitted limits and are only used for the purpose of comparing emission limits during compliance testing and operating rate during testing for combustion turbines in Rule 62-297.310 (2) F.A.C. The suggested wording of the permitting note is: *{Permitting Note: The nominal heat input values in this condition are only used to assess compliance of emission limits during testing pursuant to Rule 62-297.310(2), F.A.C.}*

Please note that the turbines are equipped with continuous emission monitoring systems (CEMS) to continuously monitor nitrogen oxides (NO_x) emissions for the purpose of demonstrating continuous compliance with this emission limit.

Appendix I: Insignificant Emissions Sources

The Insignificant Emissions Unit List for DCEP includes an indirect fired fuel gas heater with a maximum heat input rating of 13.5 MMBtu/hr (HHV). Since the potential emissions of all regulated air pollutants are less than 5 tons per year, based on Rule 62-213.300(2)(a)1, the emission unit is considered to be insignificant. Based on the heat input rating for the heater, DeSoto County Generating Company believes that the unit is subject to Title 40, Part 60 of the Code of Federal Regulations (40 CFR Part 60), Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. However, the unit fires only natural gas and as such is only subject to recordkeeping and reporting requirements contained in 40 CFR 60, Subpart Dc. The following recordkeeping and reporting requirements apply to the unit:

- Recordkeeping – Based on 40 CFR 60.48c(g)(2), the amount of natural gas combusted during each calendar month should be recorded and maintained. Based on 40 CFR 60.48c(i), the records should be maintained for a period of 2 years following the date of such record.
- Reporting – Based on 40 CFR 60.48c(j), The reporting period for the reports is each 6-month period. All reports are required to be submitted to the Administrator and postmarked by the 30th day following the end of the reporting period.

Since the emissions unit emits no "emissions-limited pollutant" and is subject to no unit-specific work practice standard, DeSoto County Generating Company requests that the gas heater be listed as an "Unregulated" emission unit.

Section III, Subsection A, Specific Condition A.22: Compliance with CO Emission Limit

Specific Condition A.22 provides the compliance determination for CO emission limit as an initial test and annual testing using EPA Method 10. DeSoto County Generating Company requests that the testing frequency be eased to once every 5 years prior to the Title V renewal. Since the units are identical, Desoto County Generating Company also requests that the testing be performed on only one unit and alternating the unit tested each 5 years. Based on the Annual Operating Reports, over the period of past 5 years, each of these units operated for less than 1,000 hours per year. The actual operating hours are provided below:

	CT 1 (hrs/yr)	**CT 2 (hrs/yr)**
2007	94	104
2008	19	9
2009	49	25
2010	19	58
2011	537	698

No other changes are requested or necessary.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Two Nominal 170-MW simple-cycle combustion turbine-electrical generators with evaporative inlet cooler.

3. Emissions Unit Identification Number: **001 and 002**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**4/2000**	**4/12/02 (Unit 1)** **4/23/02 (Unit 2)**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241FA**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    Emission unit consists of two, dual-fuel, nominal 170-MW combustion turbine-electrical generators with evaporative inlet coolers operating in simple cycle mode. These units are fired primarily by natural gas, with fuel oil used as a back-up fuel.

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: **Water Injection**	
2. Control Device or Method Code: **028**	

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: **Low NOx Burners**	
2. Control Device or Method Code: **205**	

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate:
2.	Maximum Production Rate: **340 MW**
3.	Maximum Heat Input Rate: **3,612** million Btu/hr **(LHV)**
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **6,780** hours/year
6.	Operating Capacity/Schedule Comment: **Maximum production and heat input rates represent two combustion turbines (1,806 MMbtu/hr x 2 = 3,612 MMbtu/hr). Maximum heat input rate based on nominal heat input rate due to lower heating value (LHV) of both fuels at ambient conditions of 59°F, 60% relative humidity, 100% load, and 14.7 psi pressure (ISO).** **Nominal heat input rate due to natural gas is 1,612 MMBtu/hr.** **Nominal heat input rate due to No. 2 or distillate fuel oil is 1,806 MMBtu/hr.** **Maximum operating hours represent two combustion turbines combined and an average permitted operation of 3,390 hr/yr for each (1,000 burning fuel oil plus 2,390 burning natural gas).** **Single combustion turbine operating hours limited to 5,000 hr/yr.**

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CT1 and CT2**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each CT 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: **23** feet
8. Exit Temperature: **1,113**°F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **419.75** North (km): **3011.5**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are for each combustion turbine and based on Title V operating permit application submitted June 2007.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal combustion engines; Electric Generation; Natural gas; Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **3.394**	5. Maximum Annual Rate: **11,505.7**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950 (LHV)**
10. Segment Comment: **Based on nominal heat input rate of 1,612 MMBtu/hr and 3,390 hr/yr of operation.** **Nominal Hourly rate = 2 turbines x 1,612 MMBtu/hr / 950 MMBtu/MMcf = 3.394 MMcf/hr** **Nominal Annual rate= 3.394 MM ft/hr x 3,390 hr/yr = 11,505.7 MMcf/yr** **Note: Maximum Hourly and Annual rates based on nominal heat input values.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal combustion engines; Electric Generation; Distillate Oil (Diesel); Turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons burned**	
4. Maximum Hourly Rate: **27.78**	5. Maximum Annual Rate: **27,785**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130 (LHV)**
10. Segment Comment: **Based on nominal heat input rate of 1,806 MMBtu/hr and 1,000 hr/yr of operation.** **Nominal Hourly rate = 2 turbines x 1,806 MMBtu/hr / 130 MMBtu/Mgal = 27.785 Mgal/hr** **Nominal Annual rate= 27.785 Mgal/hr x 1,000 hr/yr = 27,785 Mgal/yr** **Note: Maximum Hourly and Annual rates based on nominal heat input values.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			EL
NOX	028, 205		EL
PM			EL
PM10			EL
VOC			EL
CO			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **197.4** lb/hour **110.65** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **98.7 lb/hr (ISO)** Reference: **Permit No. 0270016-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:
(Fuel oil firing) 2 turbines x 98.7 lb/hr = 197.4 lb/hr

Annual:
(5 lb/hr x 2,390 hr/yr + 98.7 lb/hr x 1,000 hr/yr) x 2 turbines x ton/2,000 lb = 110.65 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

For each turbine, emissions from natural gas firing are limited to 5 lb/hr and emissions from fuel oil firing are limited to 98.7 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5 lb/hr (ISO) per CT**	4. Equivalent Allowable Emissions: **10** lb/hour **16.95** tons/year
5. Method of Compliance: **Use of pipeline natural gas. Fuel sulfur content limited to 1 gr/100 scf.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. Natural gas firing. Annual emissions = 5 lb/hr x 3,390 hr/yr x 2 turbines x ton/2,000 lb = 16.95 TPY**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **98.7 lb/hr (ISO) per CT**	4. Equivalent Allowable Emissions: **197.4** lb/hour **98.7** tons/year
5. Method of Compliance: **Fuel analysis. Fuel sulfur content limited to 0.05%.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. Fuel oil firing. Annual emissions = 98.7 lb/hr x 1,000 hr/yr x 2 turbines x ton/2,000 lb = 98.7 TPY**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **702** lb/hour **504.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **42 ppmvd @ 15% O2 (oil firing)** Reference: **Permit No. 0270016-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:
(Fuel oil firing) 351 lb/hr x 2 turbines = 702 lb/hr

Annual:
(64.1 lb/hr x 2,390 hr/yr + 351 lb/hr x 1,000 hr/yr) x 2 turbines x ton/2,000 lb = 504.2 TPY

Hourly emissions based on ISO conditions.

11. Potential, Fugitive, and Actual Emissions Comment:

For each turbine, emissions from natural gas firing are limited to 64.1 lb/hr and emissions from fuel oil firing are limited to 351 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9 ppmvd @ 15% O2**	4. Equivalent Allowable Emissions: **128.2** lb/hour **217.3** tons/year
5. Method of Compliance: **CEMS data (24-hr Block average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Natural gas firing.** **Annual emissions = 64.1 lb/hr x 3,390 hr/yr x 2 turbines x ton/2,000 lb = 217.3 TPY** **Hourly emissions based on ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **42 ppmvd @ 15% O2**	4. Equivalent Allowable Emissions: **702** lb/hour **351** tons/year
5. Method of Compliance: **CEMS data (3-hr Block average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Fuel oil firing.** **Annual emissions = 351 lb/hr x 1,000 hr/yr x 2 turbines x ton/2,000 lb = 351 TPY** **Hourly emissions based on ISO conditions.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **34** lb/hour **40.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **17 lb/hr (fuel oil firing)** Reference: **Permit No. 0270016-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:
(Fuel oil firing) 2 turbines x 17 lb/hr = 34 lb/hr

Annual:
(10 lb/hr x 2,390 hr/yr + 17 lb/hr x 1,000 hr/yr) x 2 turbines x ton/2,000 lb = 40.9 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

For each turbine, emissions from natural gas firing are limited to 10 lb/hr and emissions from fuel oil firing are limited to 17 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 lb/hr per CT**	4. Equivalent Allowable Emissions: **20** lb/hour **33.9** tons/year
5. Method of Compliance: **Use of pipeline natural gas. Visible emissions testing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Natural gas firing.** **Annual emissions = 10 lb/hr x 3,390 hr/yr x 2 turbines x ton/2,000 lb = 33.9 TPY**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **17 lb/hr per CT**	4. Equivalent Allowable Emissions: **34** lb/hour **17** tons/year
5. Method of Compliance: **Visible emissions testing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Fuel oil firing.** **Annual emissions = 17 lb/hr x 1,000 hr/yr x 2 turbines x ton/2,000 lb = 17 TPY**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **34** lb/hour **40.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **17 lb/hr (fuel oil firing)** Reference: **Permit No. 0270016-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:
(Fuel oil firing) 2 turbines x 17 lb/hr = 34 lb/hr

Annual:
(10 lb/hr x 2,390 hr/yr + 17 lb/hr x 1,000 hr/yr) x 2 turbines x ton/2,000 lb = 40.9 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

For each turbine, emissions from natural gas firing are limited to 10 lb/hr and emissions from fuel oil firing are limited to 17 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 lb/hr per CT**	4. Equivalent Allowable Emissions: **20** lb/hour **33.9** tons/year
5. Method of Compliance: **Use of pipeline natural gas. Visible emissions testing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Natural gas firing.** **Annual emissions = 10 lb/hr x 3,390 hr/yr x 2 turbines x ton/2,000 lb = 33.9 TPY**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **17 lb/hr per CT**	4. Equivalent Allowable Emissions: **34** lb/hour **17** tons/year
5. Method of Compliance: **Visible emissions testing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Fuel oil firing.** **Annual emissions = 17 lb/hr x 1,000 hr/yr x 2 turbines x ton/2,000 lb = 17 TPY**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **32.4** lb/hour **22.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7 ppmvw (oil firing)** Reference: **Permit No. 0270016-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:
(Fuel oil firing) 2 turbines x 16.2 lb/hr = 32.4 lb/hr

Annual:
(2.8 lb/hr x 2,390 hr/yr + 16.2 lb/hr x 1,000 hr/yr) x 2 turbines x ton/2,000 lb = 22.9 TPY
Hourly emissions based on ISO conditions.

11. Potential, Fugitive, and Actual Emissions Comment:

For each turbine, emissions from natural gas firing are limited to 2.8 lb/hr or 1.4 ppmvd and emissions from fuel oil firing are limited to 16.2 lb/hr or 7 ppmvw.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.4 ppmvd or 2.8 lb/hr (ISO) per CT**	4. Equivalent Allowable Emissions: **5.6** lb/hour **9.5** tons/year
5. Method of Compliance: **Initial stack test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Natural gas firing.** **Annual emissions = 2.8 lb/hr x 3,390 hr/yr x 2 turbines x ton/2,000 lb = 9.5 TPY**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7 ppmvw or 16.2 lb/hr (ISO) per CT**	4. Equivalent Allowable Emissions: **32.4** lb/hour **16.2** tons/year
5. Method of Compliance: **Initial stack test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Fuel oil firing.** **Annual emissions = 16.2 lb/hr x 1,000 hr/yr x 2 turbines x ton/2,000 lb = 16.2 TPY**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **142.8** lb/hour **173** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **20 ppmvd (oil firing)** Reference: **Permit No. 0270016-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:
(Fuel oil firing) 2 turbines x 71.4 lb/hr = 142.8 lb/hr

Annual:
(42.5 lb/hr x 2,390 hr/yr + 71.4 lb/hr x 1,000 hr/yr) x 2 turbines x ton/2,000 lb = 173 TPY
Hourly emissions based on ISO conditions.

11. Potential, Fugitive, and Actual Emissions Comment:

For each turbine, emissions from natural gas firing are limited to 42.5 lb/hr and emissions from fuel oil firing are limited to 71.4 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12 ppmvd or 42.5 lb/hr (ISO) per CT**	4. Equivalent Allowable Emissions: **85** lb/hour **144.1** tons/year
5. Method of Compliance: **Stack test using EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Natural gas firing.** **Annual emissions = 42.5 lb/hr x 3,390 hr/yr x 2 turbines x ton/2,000 lb = 144.1 TPY**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd or 71.4 lb/hr (ISO) per CT**	4. Equivalent Allowable Emissions: **142.8** lb/hour **71.4** tons/year
5. Method of Compliance: **Stack test using EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400, F.A.C. Fuel oil firing.** **Annual emissions = 71.4 lb/hr x 1,000 hr/yr x 2 turbines x ton/2,000 lb = 71.4 TPY**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.** **VE emissions serve as surrogate for PM/PM_{10}. Limit is for either oil or gas.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **2 hrs / 24 hrs**	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **Rule 62-210.700(1), F.A.C., allows for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Environmental** Model Number: **42C**	Serial Number: **42CHL71720-369**
5. Installation Date: **18-May-02**	6. Performance Specification Test Date: **Previously submitted**
7. Continuous Monitor Comment: **40 CFR 75 requirement.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1400**	Serial Number: **1420/3170**
5. Installation Date: **18-May-02**	6. Performance Specification Test Date: **Previously submitted**
7. Continuous Monitor Comment: **40 CFR 75 requirement.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **DCEP-EU1-I1** ☐ Previously Submitted, Date ______
2.	Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **DCEP-EU1-I2** ☐ Previously Submitted, Date ______
3.	Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **DCEP-EU1-I3** ☐ Previously Submitted, Date ______
4.	Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **DCEP-EU1-I4** ☐ Previously Submitted, Date ______ ☐ Not Applicable (construction application)
5.	Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **DCEP-EU1-I5** ☐ Previously Submitted, Date ______ ☐ Not Applicable
6.	Compliance Demonstration Reports/Records: ☐ Attached, Document ID: ______ Test Date(s)/Pollutant(s) Tested: ______ ☒ Previously Submitted, Date: ______ Test Date(s)/Pollutant(s) Tested: **5/19/11 / NOx, CO** ☐ To be Submitted, Date (if known): ______ Test Date(s)/Pollutant(s) Tested: ______ ☐ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute: ☐ Attached, Document ID: ______ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID: ________ ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ________ ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ________ ☐ Not Applicable

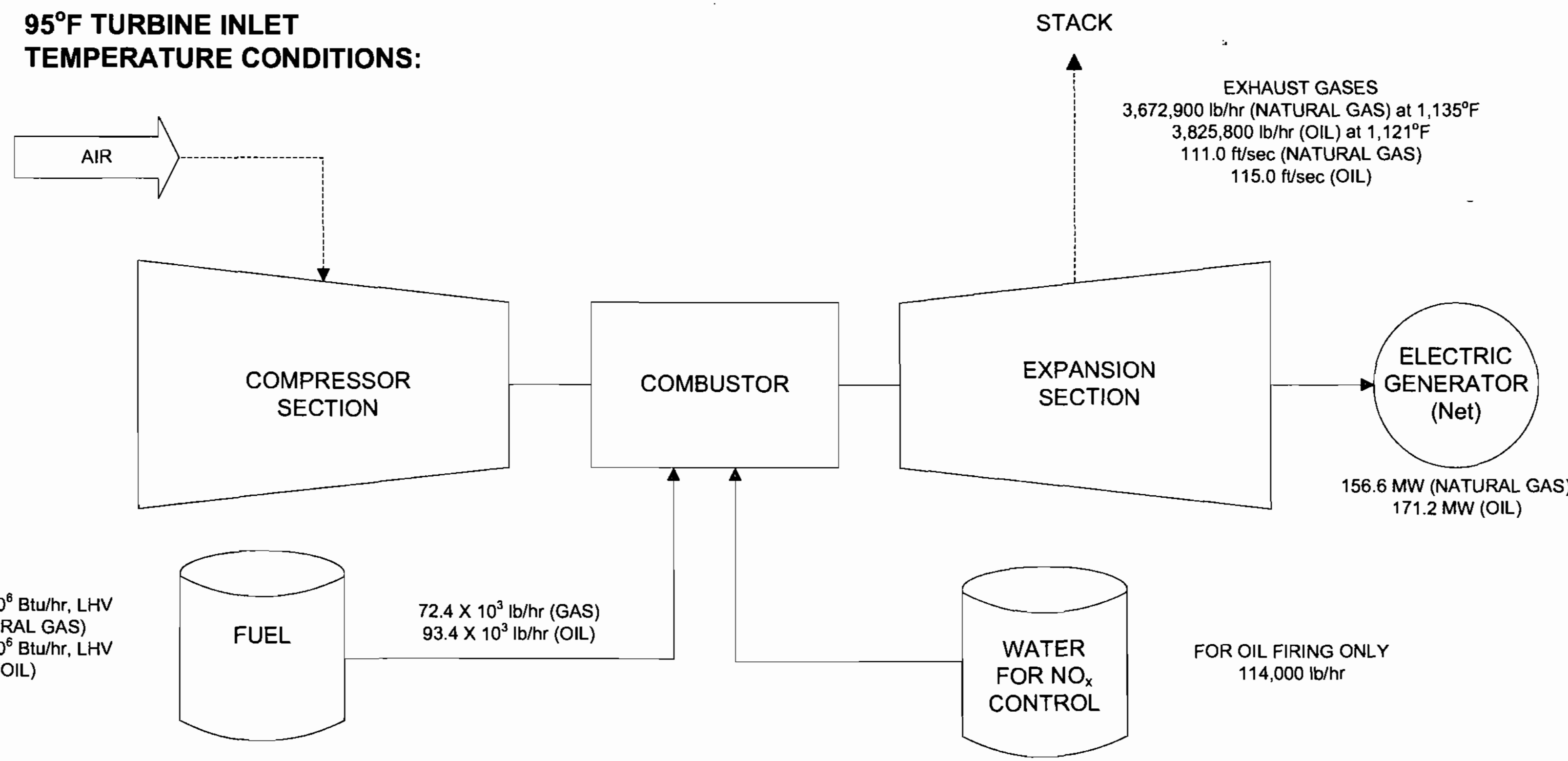
Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: DCEP-EU1-IV1
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: ________ ☒ Not Applicable
3.	Alternative Methods of Operation: ☒ Attached, Document ID: DCEP-EU1-IV3 ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT DCEP-EU1-I1

PROCESS FLOW DIAGRAM



NOTE: Information based on nominal values.

Attachment DCEP-EU1-I1a
Simplified Flow Diagram of GE Frame 7FA
Combustion Turbine
Baseload, Summer Design Conditions

Process Flow Legend
Solid/Liquid ————→
Gas - - - - - →
Steam ·········→

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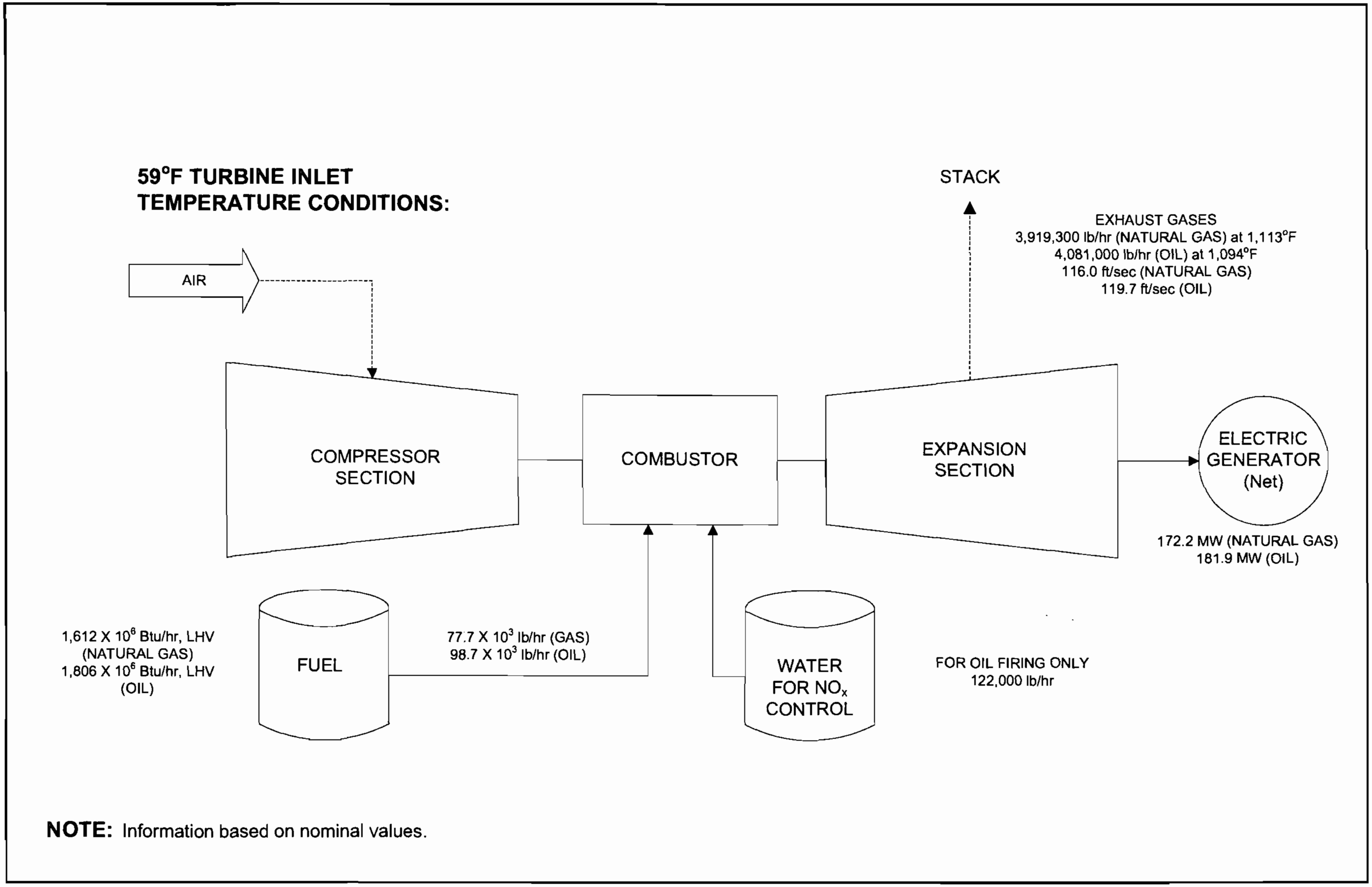

Attachment DCEP-EU1-I1b
Simplified Flow Diagram of GE Frame 7FA
Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid ———→
Gas - - - - - →
Steam ········→

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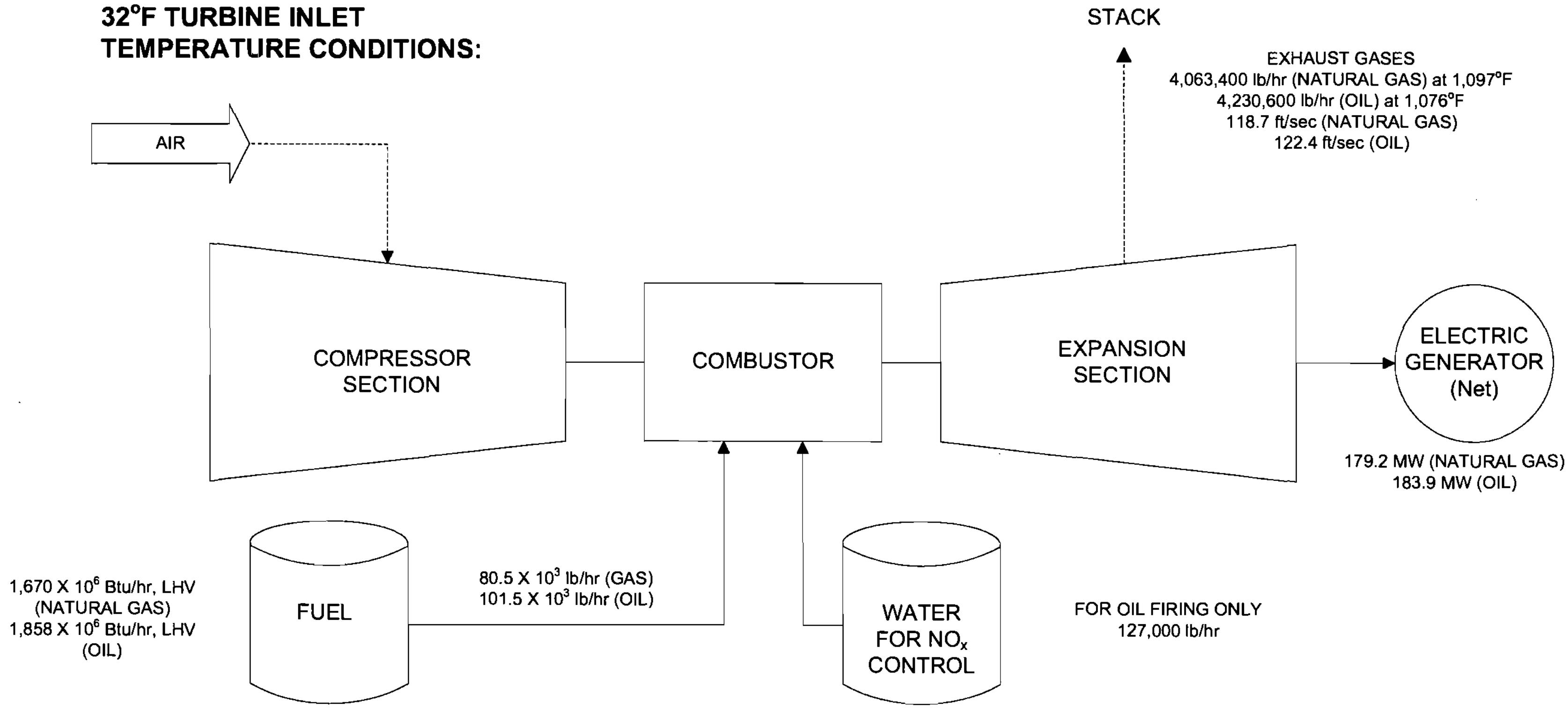
32°F TURBINE INLET TEMPERATURE CONDITIONS:



NOTE: Information based on nominal values.

Attachment DCEP-EU1-I1c
Simplified Flow Diagram of GE Frame 7FA Combustion Turbine
Baseload, Winter Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT DCEP-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

FLORIDA POWER & LIGHT CO
ENERGY MARKETING & TRADING, 700 UNIVERSE BOULEVARD [EMT/JB], ATTN: EMT FUEL OIL ACCOUNTANT
33408 JUNO BEACH FL
United States

Saybolt
A CORE LABORATORIES COMPANY
FAST TO THE POINT.

SAYBOLT LP
2610 S. Federal Hwy
Ft Lauderdale, Florida
33316
Phone: (954)524-8772
Fax: (954)524-2377
E-mail: Saybolt.ftlauderdale@corelab.com
Handled by: Armando Mejia

CERTIFICATE OF ANALYSIS

[redacted]ence	ULSD@DESOTO-JAN2012
Report no.	13056/2684 .01.I/12
Report date	06/Feb/2012
Object	Shore Tank #1 - Gauging, Sampling & Analysis
Product	# 2 FUEL OIL
Location	Arcadia, Florida, DeSoto County Plant
Outturn Date	03/Feb/2012

Sample submitted as	# 2 FUEL OIL	
Received	Sampled by Saybolt Inspector	
Marked	Shore tank # 1	
Date of sampling	03/Feb/2012	
Testing completed	07/Feb/2012	Time
Sealed	Open	
Lab number	0247	

Test	Analyte	Unit	Method	Specification	Result Prefix	Result Figure
Flash Point (PM)	Flash Point	°F	ASTM D 93A	140 min		150
Pour Point	Pour Point	°C	ASTM D 97	15 max		-9
Water and Sediment	Water and Sediment	vol%	ASTM D95/473	0.05 max		0.001
Ash	Ash	wt%	ASTM D 482	0.01 max		0.0001
Viscosity 100 °F	Viscosity 100 °F	SSU	ASTM D 445	40 max		37.06
API gravity at 60 °F		°API	ASTM D 4052	30 - 40		36.2
Sodium (Na)	Sodium (Na)	mg/kg	AA	0.5 max	<	0.1
Potassium	Potassium	mg/kg	AA	0.5 max	<	0.1
[redacted]ium	Calcium	mg/kg	AA	0.5 max	<	0.1
Lead	Lead	mg/kg	AA	0.5 max		0.4
Vanadium	Vanadium (V)	mg/kg	AA	0.5 max	<	0.5
Carbon Res. Ramsbottom	Carbon Res. Ramsbottom	wt%	ASTM D 524	0.35 max		0.04
Distillation	90% Recovered	°F	ASTM D 86	640 max		625.3
Distilaltion	Final Boiling Point	°F	ASTM D 86	690 max		681.8
Color	Visual		Visual	Report		Red
Copper corrosion	Copper corrosion		ASTM D 130	1 max		1A
Neutrality	Neutrality		ASTM D 974	Report		Neutral
Cetane Number	Cetane		ASTM D 4737A	40 min		49.4
Heat of Combustion	Heat of Combustion	MMBTU/BBL	ASTM D 240	Report		5.721
Particulate Contamination	Particulate Contamination	mg/kg	ASTM D 5452	10 max		1.13
Dupont Stability	Dupont		Dupont	7.0 max		#2
Sulfur	Sulfur	wt%	ASTM D 4294	0.0015 max		0.0010

Precision parameters apply in the evaluation of the test results specified above. Please also refer to ASTM D3244 (except for analysis of RFG), IP367 and appendix E of IP standard methods for analysis and testing with respect to the utilization of test data to determine conformance with specifications.

This report is issued in accordance with the General Terms and Conditions of Saybolt Fort Lauderdale and the recipient is deemed to have full knowledge thereof.

[redacted]rks

Armando mejia

Florida Gas Transmission

Total Sulfur Previous Day

05/17/2012 08:00 AM

Stream History

	Perry 36" Stream #1		Perry 30" Stream #2		Perry 24" Stream #3		Brooker 24" Stream	
Gas Day	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf
05/15/2012	0.889	0.056	0.823	0.051	0.984	0.061	2.195	0.137
05/15/2012	0.807	0.050	1.144	0.072	0.984	0.061	3.327	0.208
05/14/2012	0.809	0.051	1.157	0.072	0.984	0.061	3.542	0.221
05/13/2012	0.795	0.050	1.130	0.071	0.984	0.061	2.297	0.144
05/12/2012	0.772	0.048	1.013	0.063	0.984	0.061	2.576	0.161
05/11/2012	0.791	0.049	1.008	0.063	0.984	0.061	2.827	0.177
05/10/2012	0.763	0.048	1.143	0.071	0.984	0.061	0.014	0.001
05/09/2012	0.738	0.046	1.020	0.064	0.984	0.061	0.011	0.001
05/08/2012	0.748	0.047	1.009	0.063	0.984	0.061	0.016	0.001
05/07/2012	0.764	0.048	1.059	0.066	0.984	0.061	0.013	0.001
05/06/2012	0.719	0.045	1.023	0.064	0.984	0.061	0.019	0.001
05/05/2012	0.661	0.041	1.157	0.072	0.984	0.061	0.014	0.001
05/04/2012	0.697	0.044	1.193	0.075	0.984	0.061	0.013	0.001
05/03/2012	0.752	0.047	1.226	0.077	0.984	0.061	1.021	0.064
05/02/2012	0.699	0.044	1.340	0.084	0.984	0.061	2.029	0.127
05/01/2012	0.708	0.044	1.080	0.067	0.984	0.061	1.899	0.119
04/30/2012	0.728	0.045	1.184	0.074	0.984	0.061	1.945	0.122
04/29/2012	0.697	0.044	1.195	0.075	0.984	0.061	1.745	0.109
04/28/2012	0.693	0.043	1.246	0.078	0.984	0.061	1.838	0.115
04/27/2012	0.641	0.040	1.050	0.066	0.984	0.061	1.492	0.093
04/26/2012	0.630	0.039	1.225	0.077	0.984	0.061	1.524	0.095
04/25/2012	0.623	0.039	1.382	0.086	0.984	0.061	1.488	0.093
04/24/2012	0.630	0.039	1.455	0.091	0.984	0.061	1.268	0.079
04/23/2012	0.630	0.039	1.550	0.097	0.984	0.061	1.252	0.078
04/22/2012	0.765	0.048	1.531	0.096	0.984	0.061	1.456	0.091
04/21/2012	0.717	0.045	1.395	0.087	0.984	0.061	1.841	0.115
04/20/2012	0.690	0.043	1.408	0.088	0.984	0.061	2.010	0.126
04/19/2012	0.863	0.054	1.484	0.093	0.984	0.061	2.088	0.131
04/18/2012	1.461	0.091	1.911	0.119	0.984	0.061	2.203	0.138
04/17/2012	1.219	0.076	1.703	0.106	0.984	0.061	2.098	0.131
04/16/2012	1.597	0.100	1.789	0.112	0.984	0.061	2.018	0.126
04/15/2012	1.362	0.085	1.509	0.094	0.984	0.061	1.865	0.117
04/14/2012	1.299	0.081	1.611	0.101	0.984	0.061	1.818	0.114
04/13/2012	1.568	0.098	1.952	0.122	0.984	0.061	1.521	0.095
04/12/2012	1.490	0.093	1.625	0.102	0.984	0.061	0.014	0.001
04/11/2012	1.240	0.078	1.560	0.098	0.984	0.061	0.447	0.028
04/10/2012	0.781	0.049	1.339	0.084	0.984	0.061	1.690	0.106
04/09/2012	0.824	0.052	1.462	0.091	0.984	0.061	1.595	0.100
04/08/2012	0.827	0.052	1.393	0.087	0.984	0.061	0.896	0.056
04/07/2012	0.883	0.055	1.335	0.083	0.984	0.061	1.279	0.080

Florida Gas Transmission

Total Sulfur Previous Day

05/17/2012 08:00 AM

	Perry 36" Stream #1		Perry 30" Stream #2		Perry 24" Stream #3		Brooker 24" Stream	
Gas Day	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf
04/06/2012	0.887	0.055	1.352	0.084	0.984	0.061	1.557	0.097
04/05/2012	0.909	0.057	1.380	0.086	0.984	0.061	1.837	0.115
04/04/2012	0.907	0.057	1.531	0.096	0.984	0.061	1.913	0.120
04/03/2012	0.867	0.054	1.444	0.090	0.984	0.061	2.019	0.126
04/02/2012	0.909	0.057	1.471	0.092	0.984	0.061	2.000	0.125
04/01/2012	0.937	0.059	1.530	0.096	0.984	0.061	1.771	0.111
03/31/2012	0.965	0.060	1.555	0.097	0.984	0.061	1.537	0.096
03/30/2012	0.967	0.060	1.582	0.099	0.984	0.061	1.792	0.112
03/29/2012	1.020	0.064	1.549	0.097	0.984	0.061	1.935	0.121
03/28/2012	1.109	0.069	1.779	0.111	0.984	0.061	1.756	0.110
03/27/2012	1.084	0.068	1.534	0.096	0.984	0.061	1.725	0.108
03/26/2012	1.019	0.064	1.465	0.092	0.984	0.061	1.602	0.100
03/25/2012	1.056	0.066	1.522	0.095	0.984	0.061	1.553	0.097
03/24/2012	1.048	0.065	1.476	0.092	0.984	0.061	1.598	0.100
03/23/2012	1.067	0.067	1.488	0.093	0.984	0.061	1.850	0.116
03/22/2012	0.979	0.061	1.089	0.068	0.984	0.061	1.758	0.110
03/21/2012	1.074	0.067	1.437	0.090	0.984	0.061	1.855	0.116
03/20/2012	1.109	0.069	1.442	0.090	0.984	0.061	1.706	0.107
03/19/2012	1.065	0.067	1.502	0.094	0.984	0.061	1.742	0.109
03/18/2012	1.079	0.067	1.590	0.099	0.984	0.061	1.683	0.105
03/17/2012	1.170	0.073	1.632	0.102	0.984	0.061	1.714	0.107
03/16/2012	1.176	0.073	1.590	0.099	0.984	0.061	1.957	0.122
03/15/2012	1.223	0.076	1.565	0.098	0.984	0.061	1.804	0.113
03/14/2012	1.095	0.068	1.145	0.072	0.984	0.061	1.323	0.083
03/13/2012	1.127	0.070	1.181	0.074	0.984	0.061	1.142	0.071
03/12/2012	1.135	0.071	1.323	0.083	0.984	0.061	1.360	0.085
03/11/2012	1.152	0.072	1.391	0.087	0.984	0.061	1.108	0.069
03/10/2012	1.141	0.071	1.336	0.084	0.984	0.061	1.279	0.080
03/09/2012	1.240	0.078	1.326	0.083	0.984	0.061	1.617	0.101
03/08/2012	1.198	0.075	1.458	0.091	0.984	0.061	1.620	0.101
03/07/2012	1.199	0.075	1.465	0.092	0.984	0.061	1.292	0.081
03/06/2012	1.268	0.079	1.449	0.091	0.984	0.061	1.108	0.069
03/05/2012	1.153	0.072	1.360	0.085	0.984	0.061	0.962	0.060
03/04/2012	1.163	0.073	1.328	0.083	0.984	0.061	0.015	0.001
03/03/2012	1.127	0.070	1.180	0.074	0.984	0.061	0.014	0.001
03/02/2012	1.098	0.069	1.300	0.081	0.984	0.061	0.014	0.001
03/01/2012	1.158	0.072	1.378	0.086	0.984	0.061	0.990	0.062
02/29/2012	1.066	0.067	1.353	0.085	0.984	0.061	1.607	0.100
02/28/2012	1.128	0.070	1.518	0.095	0.984	0.061	1.877	0.117
02/27/2012	1.139	0.071	1.592	0.099	0.984	0.061	1.924	0.120
02/26/2012	1.127	0.070	1.693	0.106	0.984	0.061	1.436	0.090
02/25/2012	1.083	0.068	1.623	0.101	0.984	0.061	1.560	0.097
02/24/2012	1.060	0.066	1.414	0.088	0.984	0.061	2.030	0.127
02/23/2012	1.013	0.063	1.340	0.084	0.984	0.061	2.072	0.129
02/22/2012	1.036	0.065	1.418	0.089	0.984	0.061	1.728	0.108
02/21/2012	1.033	0.065	1.492	0.093	0.984	0.061	1.779	0.111

Florida Gas Transmission

Total Sulfur Previous Day

05/17/2012 08:00 AM

	Perry 36" Stream #1		Perry 30" Stream #2		Perry 24" Stream #3		Brooker 24" Stream	
Gas Day	**Avg ppm**	**Avg Grains/hcf**	**Avg ppm**	**Avg Grains/hcf**	**Avg ppm**	**Avg Grains/hcf**	**Avg ppm**	**Avg Grains/hcf**
02/20/2012	1.014	0.063	1.583	0.099	0.984	0.061	1.677	0.105
02/19/2012	0.942	0.059	1.338	0.084	0.984	0.061	1.870	0.117
02/18/2012	0.900	0.056	1.061	0.066	0.984	0.061	2.030	0.127
02/17/2012	0.959	0.060	1.031	0.064	0.984	0.061	1.900	0.119
02/16/2012	0.999	0.062	0.992	0.062	0.984	0.061	1.552	0.097
02/15/2012	0.909	0.057	0.994	0.062	0.984	0.061	1.450	0.091
02/14/2012	0.782	0.049	0.951	0.059	0.984	0.061	1.411	0.088
02/13/2012	0.845	0.053	1.058	0.066	0.984	0.061	0.902	0.056
02/12/2012	0.872	0.054	1.521	0.095	0.984	0.061	0.470	0.029

ATTACHMENT DCEP-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

WATER INJECTION SYSTEM

GE Power Systems
Gas Turbine

Water Injection System

I. 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 SPEEDTRONIC™ control, which then regulates the system.

The water injection system, shown in the reference drawings section of this manual, 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 listing of the on-base and off-base components, together with a brief functional description of the system. More detailed information on individual items is given in the manufacturer's literature (Equipment Publications), which follows this text.

A. On-Turbine Base

1. Water injection manifold and associated piping to carry water to the manifold. Fourteen tubing arrangements to carry water to the connection points of each of fourteen combustion chambers. Fourteen flow proportioning valves, one installed in each of the tubing lines supplying each of the combustors. A low point drain is provided on the turbine base adjacent to the inlet connection point.

2. Fourteen separate combustors, each with a set of identical water injection nozzles fed from a single connection point per combustor.

B. Off-Base Skid

1. Inlet Water Strainer (FW1-2)

2. Inlet water pressure switch (63WN-1)

3. Two (2) high pressure centrifugal water injection pump/motor assemblies with motor space heaters (PW1-1/88WN-1/23WN-1) and (PW2-1/88WN-2/23WN-2).

4. Two (2) Variable Frequency Drive units with pump/motor speed feedback and alarm relay (97WN-1/96WN-4/30WN-1/84WN-1) and (97WN-2/96WN-2/30WN-2/84WN-2).

5. Water pump discharge pressure transmitter (96WP-1)

6. A duplex 40 micron absolute water filter assembly (FW1-1 and FW2-1)

7. Water filter differential pressure switch (63WN-3)

8. Two (2) Turbine Flowmeters with two identical Pick-Ups/Transmitters per flow meter (FM1-1/96WF-1/96WF-2) and (FM2-1/96WF-3/96WF-4)) and downstream strainers (FW1-3) and (FW1-4).

9. Water actuated stop valve (VS2-1) with Solenoid (20WN-1), Actuation Pressure Regulator (VPR62-11), Actuation Pressure Relief Valve (VR70-1), Quick-Exhaust Valve (VQE1-1) and "Last Chance" Filter (FW3-1).

10. Associated piping, flanges, check valve, pressure gauges, manual isolation valves, and inlet water temperature gauge.

11. Compartment ventilation/cooling fan/motor, 88JS-1, and cooling thermostat, 26JS-1, are provided to keep the skid cool. Thermostat 26JS-2, which is set at a higher temperature than 26JS-1, signals a high temperature alarm in the SPEEDTRONIC™ control.

12. Compartment heater, 23WR-1, and heating thermostat, 26WR-1, are provided to maintain skid temperature at a comfortable level, to minimize condensation, and to prevent freezing. Thermostat 26WR-2, which is set at a lower temperature than 26WR-1, signals a low temperature alarm in the SPEEDTRONIC™ control.

13. Skid lighting consists of light switch ASW-28 and AC lights AL-58, AL-59, AL-82 and AL-86. AL-58 has DC battery backup on AC failure. There are two AC power outlets, AR-41 and AR-42, each with grounded receptacles.

II. 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. The customer is responsible for supplying water to the water injection skid from the customer's treatment and storage facility (see Customer Responsibilities).

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

There are inlet and discharge manual isolation valves on both pumps (PW1-1 and PW2-1). These valves are for isolation during pump maintenance only and should be left open at all other times. There is a check valve in each of the discharge lines to prevent back flow during normal operation.

The minimum and maximum flow rates for this Gas Turbine are specified in the water Injection System Piping Schematic included in this Manual.

A discharge pressure transmitter (96WP-1) is located downstream of the pump. The signal from this transmitter is fed back to the SPEEDTRONIC™ for monitoring and fault detection.

The flow then passes through a high pressure duplex filter assembly (FW1-1 and FW2-1). 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 SPEEDTRONIC™ 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 (see Diag. Schematic PP- Water Injection Unit). 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 dual pick-ups, each with its own Flow Transmitter (96WF-1 and 96WF-2). The flowmeter provides a signal to the SPEEDTRONIC™ control system. The system also contains a redundant flowmeter (FM2-1) with dual pick-ups (96WF-3 and 96WF-4). There are manual isolation valves in these lines to direct flow through either flowmeter. Strainers (FW1-3 and FW1-4) are installed downstream of the flowmeters, to protect the other system components in the event of a flowmeter failure.

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/cm) 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.

III. 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

SPEEDTRONIC™ 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 SPEEDTRONIC™, 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 SPEEDTRONIC™ uses in the flow control loop as a feedback signal.

For a more detailed description of the control system and the operation of the water injection system, refer to the Control and Protection text in this manual.

IV. SYSTEM REQUIREMENTS

A. Customer Responsibilities

The customer must supply water meeting the requirements of Table 1.

The fluid must be water, and not water/glycol mixture. The customer must provide a storage tank of suitable size, and the necessary piping from the tank to the skid. Water must be supplied to the skid within the specified temperature and pressure ranges shown on the water injection system schematic diagram. The storage tank and related piping should be designed and positioned to deliver water to the skid within this pressure range.

The customer must provide stainless steel piping, flanges, valves, etc., to and from the water injection skid. The water storage tank must be stainless or suitably coated. The piping from the skid to the gas turbine base must be designed for a maximum pressure drop at the maximum water flow as shown on the water injection system schematic diagram.

The water Injection System shall be charged with water from the water skid supply connection WJ1 to upstream of the stop valve near WJ2 to minimize fill time and prevent air from entering the system. The storage tank, and all piping must be completely clean before the system is operated. As there are no water filters or strainers on the turbine base, this is particularly important for the piping from the skid to the turbine base. In order to ensure clean piping, the system must be flushed. For system flushing instructions, refer to long-term Shutdown Checks herein.

B. Operation

1. Long Term Shutdown Checks

   Before operating the skid for the first time, following an overhaul, or following a period of extended shutdown, it is important that the following checks be made.

   a. Verify that the water-injection pump gear-box and/or bearing housing is supplied with lubricant. The lubricant color and level should be checked. Refer to the pump manufacturer's instructions in the Skid Manufacturer's Service Manual/Equipment Publications.

   b. Check all manual valves (isolation valves etc.) for operability.

   c. Verify tightness of all flanges, bolted joints etc. to ensure against leaks.

d. Check alignment of pump and motor in accordance with the pump or skid manufacturers recommendations. Check motor mount and pump mount bolts and tighten if required.

e. Check water filter elements to ensure that they are properly seated. When replacing the filter head it is important to ensure elements remain correctly aligned, and to tighten all studs evenly. This will ensure against any leaks on startup.

f. Remove and inspect strainer baskets. Clean if necessary.

g. Verify all gauges are zeroed

h. Verify that all the settings programmed in the VFD unit are in accordance with the as-shipped values supplied by the Skid Manufacturer (refer to the Skid Manufacturer's Service Manual/Equipment Publications for these settings).

CAUTION

The variable frequency drive has been factory set and tested. Alteration of the factory settings may cause system malfunction or failure. Do not change these settings unless such a change has been approved by the manufacturer of this skid. A list of the factory settings is included in the skid service manual.

i. Jog the pump in accordance with the pump manufacturer's operating instructions.

CAUTION

Do not operate or jog the pump until the water supply has been connected to the system. Even brief operation of the pump without water can cause failure of the shaft seal.

j. The water injection skid and the piping from the skid to the turbine should be flushed on site using water of the same quality as will be used in operation. The flush should be of at least one-half hour in duration. The water discharged during flushing should not be supplied to the turbine combustors but should be drained, or reclaimed. The flushing strainer should then be checked for debris. If any debris is found, the strainer should be cleaned, re-assembled, and the skid should be flushed once again for the same time period. The strainer should then be checked again. This process should be repeated until the strainer is found to remain clean. The system should be checked for leaks during and after this flush and any leaks should be corrected. When the flush is complete, the skid filter elements should be checked for cleanliness, and replaced if necessary before continuing with system operation.

CAUTION

To prevent flowmeter damage, during flushing the flowmeter should be removed and replaced with a spool piece. Ensure that the system is vented of air prior to allowing flow through the flowmeter. Operate all manual isolation valves slowly in order to avoid shocking the flowmeter. Do not exceed the maximum flow rating of the flowmeter. Failure to comply with this procedure may cause flowmeter damage.

2. Pre-Operation Checks

The main skid isolation valves should be open. All isolation/snubbing valves in the sensing lines to pressure gauges should be open. The valve on the filter vent line should be closed.

CAUTION

> To prevent damage to the pump seals, the pump seal drain must be open to the atmosphere at all times that the pump is in operation. Do not install any kind of plug in the pump seal drain discharge. A small amount of water weepage from this drain is normal and does not indicate a seal failure. Refer to the pump manufacturers instructions. Failure to comply with this caution may cause severe damage to the pump seals.

All four manual pump isolation valves both in the pump discharge and suction lines should be open.

CAUTION

> Pump Isolation Valves are for maintenance purposes only. Unless work is being done on the pump these four isolation valves should be left open. There are check valves present in the pump discharge to prevent back flow. Pump damage or failure may result if these valves are left closed.

The flowmeter isolation valves should be positioned such that all of the flow will pass through FM1-1, leaving the second flowmeter isolated. If flow is allowed through both meters simultaneously during operation then incorrect flow readings will result.

3. Startup

When the system is started, the valve on the filter vent line should be opened slightly to bleed off any trapped air. When a steady stream of water comes out of the vent, the valve should be tightly closed.

V. MAINTENANCE

A. Periodic Maintenance

1. During the first week of operation, the system should be checked periodically for leaks or other problems. After this it should be checked at monthly intervals. Check the pump seal drain for leakage (an occasional drop of water from this drain is normal).

2. The pumps and motors should be maintained in accordance with instructions from their respective manufacturers in the section following this text.

3. Replace flowmeter bearings and re-calibrate at intervals of 8000 hours of operation, or 3 years (whichever is shorter)

4. The inlet strainer should be checked and its basket cleaned or replaced if necessary when the system is shut down.

5. The filter elements should be replaced when the filter differential pressure reaches 15 psid (1.0 kg/cm). Replace the filter elements in accordance with the manufacturer's instructions.

6. All manually operated valves should be cycled once per month to verify freedom of movement. They should be returned to their normal running position following this check.

B. Troubleshooting

If the water injection system fails to provide water to the turbine at the required flow rate or pressure, the following possible causes should be investigated.

1. Water supply exhausted: Verify adequate water supply

2. Insufficient supply pressure to water injection skid: Verify 10 psig minimum supply pressure at inlet pressure gauge.

3. Loss of pump suction: Check for air leaks in pump inlet piping. Check condition of gaskets. Tighten all joint connections.

4. Excessive inlet strainer differential (FW1-2): Verify 6 psid (0.42 kg/cm) or less from skid inlet to pump inlet. Remove and clean strainer basket if necessary.

5. Excessive filter pressure differential: Verify 15 psid (1.0 kg/cm) or less indicated on filter differential pressure gauge at design flow rate. Replace elements if dirty.

6. Variable Frequency Drive (97WN-1) not responding: Verify correct power supply and control signal to the VFD. Verify motor/pump are running at correct speed in response to control signal. Refer to VFD manufacturer's instructions in the Skid Manufacturer's Service Manual/Equipment Publications. Refer also to Turbine Control specification.

7. Stop valve (VS2-1) closed: Verify correct porting and power supply to 20WN-1 solenoid valve. Check for blockage in control pressure supply line to solenoid valve. Check for correct operation of stop valve.

8. Strainer (FW1-3) blocked: Remove and inspect. Clean if necessary. Replace and tighten all bolts.

9. Skid inlet or discharge lines blocked: Check for blockage. Verify lines are not frozen if exposed to cold temperatures.

10. Pump discharge inadequate: Verify pump to motor coupling, drive shaft, or pump impeller key has not sheared. Disassemble pump and inspect if necessary. Check pump gearbox. Verify pump is rotating in correct direction. Refer to pump manufacturer's instructions in the section following this text for further pump troubleshooting guidance.

11. Pump motor failed: Verify motor is not single-phased. Verify motor operable. Refer to motor manufacturer's instructions in the section following this text for further motor troubleshooting guidance

12. Incorrect pressure gauge or flowmeter readings: Verify calibration. Check flowmeter to ensure it is generating an output signal to the SPEEDTRONIC™ controller, and that the correct "K" factor (recorded on a tag attached to the flowmeter) is set for the flow Transmitter. Check SPEEDTRONIC™ to ensure correct calibration is programmed.

C. Long-Term Storage

The water injection skid is an enclosed structure designed to maintain the system from freezing. If the skid will not be operated for an extended period of time, the operator may choose to drain the system. However, it is still recommended that the power to the skid space heater and motor space heaters (if provided) be left connected in order to protect the skid from freezing damage and to minimize the condensation of moisture in the skid. The following procedure may be used to prepare the skid for storage

1. Close the skid inlet isolation valve.
2. Open flowmeter and pump isolation valves.
3. Open the filter vent line valve.
4. Open the filter drain.
5. Open the pump drain (e.g. by removing the plug in the lower half of the pump casing).
6. Remove the plugged tap on the line from the pump outlet.
7. Close the manual isolation valves at the skid discharge.
8. Open strainer drain to evacuate as much water as possible from the skid piping.
9. Open all low point drains in the skid piping. Allow any water present to drain fully before replacing low point drains.

When returning the skid to service, the above steps should be reversed.

Table 1
Properties of Water for Injection system
Total of Sodium (Na) + Potassium (K) + Lead (Pb) + Vanadium (V) + Lithium (Li) = 0.5 ppm maximum
Total of dissolved plus undissolved solids = 5 ppm maximum
pH = 6.5 to 7.5

NOTE

Refer also to paragraph "Non-Fuel Contaminants" in "Gas Turbine Fuel Recommendations" under FLUID SPECIFICATIONS tab.

NOTE

Refer also to GE drawing GEK 101944 for water injection water quality criteria

FUEL GAS CONTROL SYSTEM

GEK 106852B
Revised, September 2001
Replaces GFD26Q00

GE Power Systems
Gas Turbine

Fuel Gas Control System (DLN$_X$ 2.6)

These instructions do not purport to cover all details or variations in equipment nor to provide for every possible contingency to be met in connection with installation, operation or maintenance. Should further information be desired or should particular problems arise which are not covered sufficiently for the purchaser's purposes the matter should be referred to the GE Company.

TABLE OF CONTENTS

LIST OF FIGURES

I. 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, P_2, is controlled by modulating the SRV based on turbine speed as a percentage of full speed, TNH, and feedback from the P_2 pressure transducers, 96FG-2A, B, and C. Refer to the Gas Fuel System schematic.

In a Dry Low NO_x 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.

II. 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.

A. 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, P_2, 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.

Each processor of the control system computes its own FSR2, FSRPM1, 2, 3 and FSRQT and each processor drives one of the three servo valve coils. The GCVs' position control loops function similarly to the SRV's position control loop.

The servo valves are furnished with a mechanical null offset bias which causes the GCVs or SRV to move to the zero stroke position during a zero voltage input signal or an open circuiting of the servo valve coils. During calibration, checks should be made to insure this feature is functioning properly.

The SRV and GCVs are equipped with hydraulically actuated spring return dump valves. The dump valves are held in their normal operating state by a supply of hydraulic oil referred to as trip oil. The trip oil system is triple redundant to ensure that no single device failure can disturb the operation of the power generating unit.

B. Gas Control Valve (GVC) Position Control Loop

The position control loop is shown on Figure 1. Two LVDTs (96GC-1 through -8) are used on each control valve for position sensing. Their feedback signals go through the servo-amplifier where two independent transformers and a discriminator circuit demodulate the LVDT ac output to dc feedback signals acceptable for use by the position control. The highest signal is diode gated and proportioned by an amplifier to the correct valve stroke calibration. See Figure 2 for a typical calibration curve.

It is this dc signal which is fed back and compared to FSR at the summing junction of an error amplifier in the servo-driver circuitry. For stable control, the amplified error is properly proportioned to command the integrating amplifier which drives the servovalve, 65GC. When the LVDT feedback equals the FSR input signal the servo-drive amplifier summing junction is satisfied.

The Control Specifications give the correct position loop settings for a specific turbine.

C. LVDT Terminal Connections

Linear Variable Differential Transformers (LVDTs) used in SPEEDTRONIC control have special proprietary windings which requires that several of the terminals be jumpered at the first terminal board, since the SPEEDTRONIC system requires only four LVDT leads. The primary winding of the LVDTs is tapped off at the 25% point, and the connection is brought out to become one of the two output connections of the LVDT. The low voltage input connection of the primary coil must be connected to the zero stroke end connection of the secondary windings, and the null position ends of the two secondary windings must be connected to permit the secondary windings to be in series opposition. Four leads used in the SPEEDTRONIC fuel control loop are the two primary connection leads for excitation and the two special output connections. One of the output connections is the tapped connection lead of the primary winding. The other connection is the maximum stroke end connection of the secondary winding. Polarity of the tapped primary connection is opposite to the polarity of the secondary winding at zero stroke, and is in series addition to the polarity of the secondary winding at zero stroke, and is in series addition to the polarity of the secondary winding at maximum stroke. Thus, the polarity of the ac output of the LVDT, (or the rectified dc output), as used in SPEEDTRONIC control, does not reverse as the LVDT core position is moved from the zero fuel stroke to the maximum fuel stroke position. The LVDT with the proprietary output circuit is designed for an output of 0.7 volts RMS ac with the zero stroke of the valve stem and 3.5 volts RMS ac at the designed maximum stroke for the specified LVDT. The actual maximum required position of the gas control valve's stem, and travel, may be slightly less than the actual design stroke for the LVDT.

D. LVDT Oscillators

Excitation for each LVDT is provided by an oscillator in the SPEEDTRONIC panel. The output of each oscillator is 7.0 volts ac at a nominal frequency of 3000 Hz. The two oscillators, however, on the two LVDTs can cause a beat frequency equal to the difference in the frequency of the two oscillators. Therefore, one oscillator is set at 3200 Hz and the other oscillator is set at 2800 Hz to eliminate the effects of the beat frequency in the same control loop.

E. Servovalve (65GC and 90SR) Mechanical Position

The servovalves are furnished with a mechanical null offset bias to cause the gas control valves or stop/ratio valve to go to the zero stroke position on zero voltage or an open circuiting of both servovalve coils. During calibration, checks should be made to insure that this happens.

The SRV and GCVs are equipped with hydraulic supply filters which have a high differential pressure indicator for local indication.

F. Stop/Speed Ratio Valve

The SRV serves two functions. First is its operation as a stop valve, making it an integral part of the protection system. An emergency trip or normal shutdown will trip the valve to its closed position, preventing gas fuel flow to the turbine. Closing the SRV can be achieved in two ways: dumping the hydraulic oil from the SRV's hydraulic actuator cylinder, or driving the SRV closed electrically using the control system's SRV position control loop. The SRV also operates as a pressure regulating valve. The control system uses the SRV to regulate the pressure, P_2, upstream of the GCVs. See Figures 3,4.

While the SRV's position control loop is considered an inner control loop, the pressure control loop is considered an outer control loop. The control system computes a P_2 pressure command, FPRGOUT. This command is a linear function of TNH. Three pressure transducers are used to sense the intervalve pressure, P_2. Each channel of the control system computes its own FPRGOUT and each is wired to a single pressure transducer. The pressure transducers are used to determine the error between desired P_2 pressure, FPRGOUT and actual P_2 pressure. The resulting error is scaled through an integration algorithm which uses the current gas FSR command, FSR2, to compute a valve position command. Two LVDTs sense SRV stem position and their outputs are returned to each channel of the control system. The control system selects the largest feedback signal in determining the error between desired SRV valve position command and actual valve position. The error then becomes the input to the servo amplifier which drives the servo valve in the direction required to decrease the position error.

The following conditions must be satisfied before the SRV can be opened: (Either a transfer to Gas fuel must be occurring OR a 100% Liquid fuel split setpoint must not exist) AND (the master protective circuit must be enabled) AND (the Gas Fuel System purge valve(s) must be closed) AND (either flame detection control must be enabled OR the ignition permissive circuit must be enabled).

The SRV will be closed automatically on flame failure, failure to ignite on start-up, or actuation of the fire detection equipment. Following a unit trip the master protective and ignition permissive circuits are used to prohibit starting until the conditions are acceptable.

In the event of an emergency trip or normal shutdown a negative P_2 pressure is commanded by FPRGOUT. This negative command drives the SRV servo valve into negative saturation and quickly closes the SRV. However, in these situations the dumping of hydraulic fluid from the SRV actuator cylinder will allow the SRV return spring to close the valve well before the servo valve can empty the cylinder.

G. Valve Malfunction Alarms

In addition to being displayed, the feedback signals and the control signals of all valves are compared to normal operating limits, and if they should go outside of these limits, there will be an alarm. The following are typical alarms:

1. Loss of feedback.
2. Valve is open prior to permissive to open.
3. Loss of servo current signal.
4. P_2 pressure (96FG) is zero during operation.
5. Valve not following command.

The servovalves are furnished with a mechanical null offset bias to cause the gas control valve or speed ratio valve to go to the zero stroke position (fail safe condition) should the servovalve coil signals or power be lost. During a trip or no run condition, a positive voltage bias is placed on the servo coils holding them in the position calling for valve closed.

H. Calibration of Fuel Gas Pressure Transducers, 96FG-2A, 2B, 2C

The fuel gas pressure transducer, 96FG, is a pressure transducer with a dc voltage output directly proportional to pressure input in psig. It incorporates solid state circuits and an amplifier in the transducer case.

A diode is connected across the output of the transducer. This prevents any possibility of a spurious signal driving the transducer amplifier negative, out of its normal operating range.

The transducer is normally factory adjusted and calibrated; however, the calibration must be checked in the field and necessary readjustment made to meet the volts-output versus pressure-input requirements, as specified in the Control Specifications.

J. Gas Strainer

1. Y Type Strainer

   A strainer is provided in gas supply lines to remove any foreign particles from the gas fuel before it is admitted to the speed/ratio valve assembly. There is a blowdown connection on the bottom of the strainer body which should be utilized periodically for cleaning the strainer screen. A high filtration, start-up strainer basket needs to be left in the strainer until it stays clean for 48 hours of continuous operation. At which point, it should be removed and a more durable running strainer basket should be installed for continuous operation.

2. Duplex Strainer

   The duplex strainer is designed as a single unit with two strainer baskets. A basket is isolated and individually removed for cleaning while fuel is filtered through the other one. There is no blowdown. A high filtration, start-up strainer basket needs to be left in the strainer until it stays clean for 48 hours of continuous operation. At which point, it should be removed and a more durable running strainer basket should be installed for continuous operation.

3. Witch Hat Strainer

A conical strainer(s) is field installed upstream of each fuel gas manifold between two mating flanges. The strainer(s) is oriented with the tip in the opposite direction of fuel flow and is used to prevent foreign particles from entering the combustion system. Following the first ten hours of unit operation, the strainer(s) and gasket(s) are removed. A new gasket(s) should be reinstalled prior to restarting the unit.

K. Low Pressure Switch, 63FG

This pressure switch is installed in the gas piping upstream from the gas stop/speed ratio valve and control valve assembly and initiates an alarm on the annunciator panel whenever the gas pressure drops below a specified setting. On dual fuel units, this switch or a second 63FG pressure switch set below the alarm setpoint is used to initiate a transfer to liquid fuel.

L. Pressure Gauges

Three pressure gauges, with hand valves, are installed in the fuel gas supply line. The upstream pressure gauge measures the pressure of the gas entering the stop/speed ratio valve; the intermediate pressure gauge measures P_2 pressure ahead of the gas control valve; and the downstream gauge measures the pressure as the gas leaves the gas control valve.

M. Gas Fuel Vent Solenoid Valve 20VG

This solenoid valve vents the volume between the stop/speed ratio valve and the gas control valves when the solenoid is deenergized. The solenoid is energized and the vent valve closed when the master control protection circuit is energized and the turbine is above the cooldown slow roll speed. It will be closed and remain closed during gas fuel operation.

The vent is open when the turbine is shut down because the stop/speed ratio and gas control valves have metal plugs and metal seats and therefore, are not leak tight. The vent insures that during the shutdown period, fuel gas pressure will not build up between the stop/speed ratio and gas control valves, and that no fuel gas will leak past the closed gas control valve to collect in the combustors or exhaust.

If the vent valve fails during normal operation the SRV will continue to maintain constant pressure, P_2. This is accomplished by opening further, making up any lost flow through the vent valve.

N. Routing of Vent Lines by Customer/Installer

FG3 and FG2 are potential Class 1, Div 1 sources of natural gas. Installer shall route these lines separate from each other and from all other vents, to a naturally ventilated area outside of any buildings or enclosures, and in an area free from sources of ignition. The extent of the hazardous area created by FG3 is a 5 ft Class 1, Div 1, Group D spherical radius and area between 5 ft and 10 ft is considered to be a Class 1, Div 2, Group D spherical radius. The minimum extent of the hazardous area created by FG2 is a Class 1, Div1, Group D cylinder that extends 5 ft upstream and 10 ft downstream of the FG2 termination with a 10 ft radius. Additionally a Class 1, Div2, Group D hazardous area extends 5ft upstream and 10 ft in all other directions around the FG2 Class 1, Div 1, Group D hazardous area. The actual extent of the hazardous area created FG2 vent will depend on the volume of gas released when the manual strainer blowdown valve is operated, and the pressure temperature and density of the gas present at FG1 at the time the strainer blowdown/vent valve is operated.

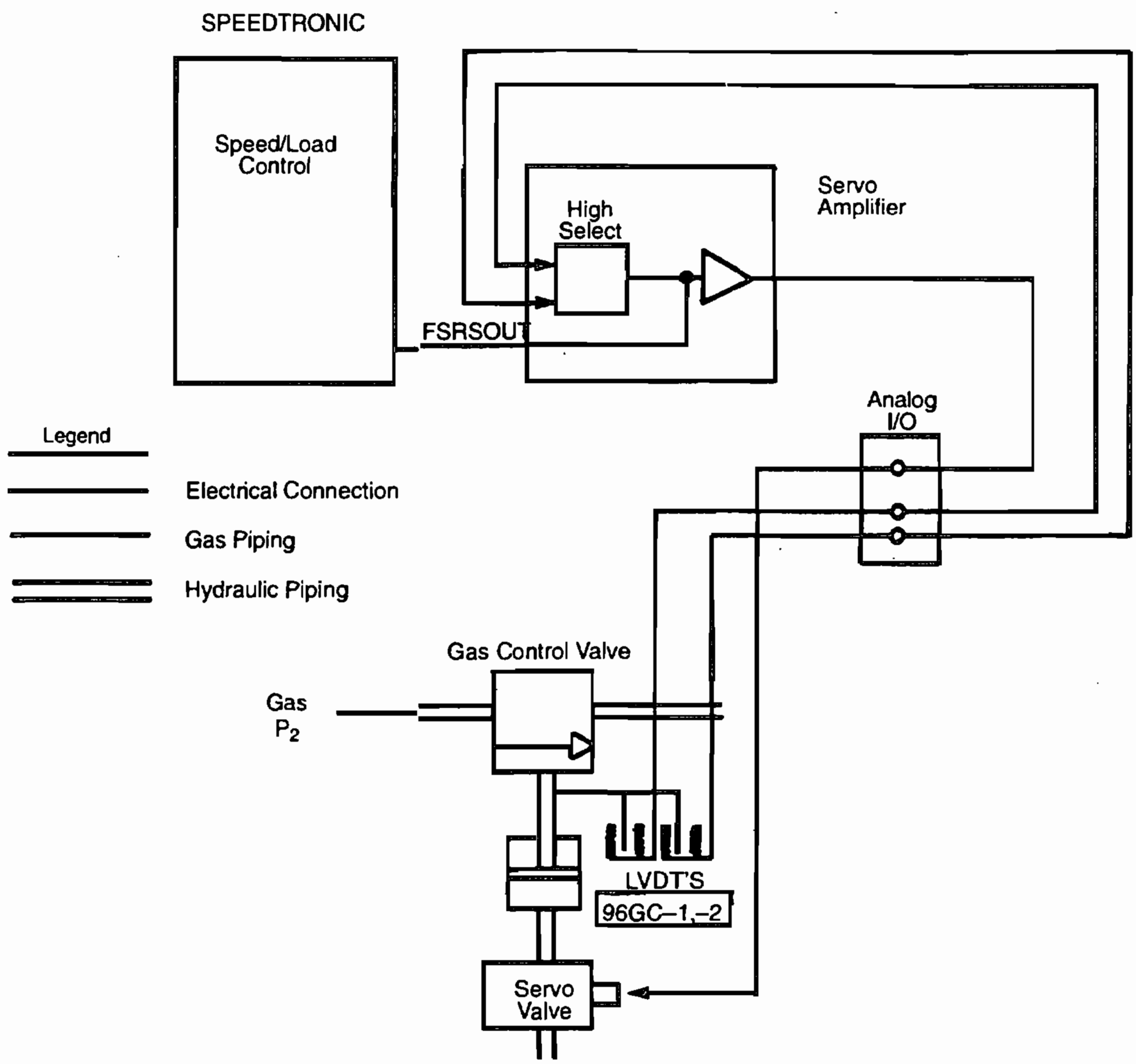

Figure 1. Gas Control Valve Control Schematic.

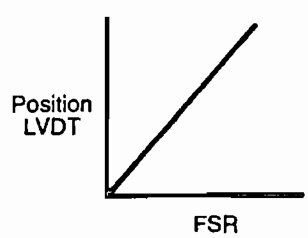

Figure 2. Gas Control Valve Position Loop Calibration.

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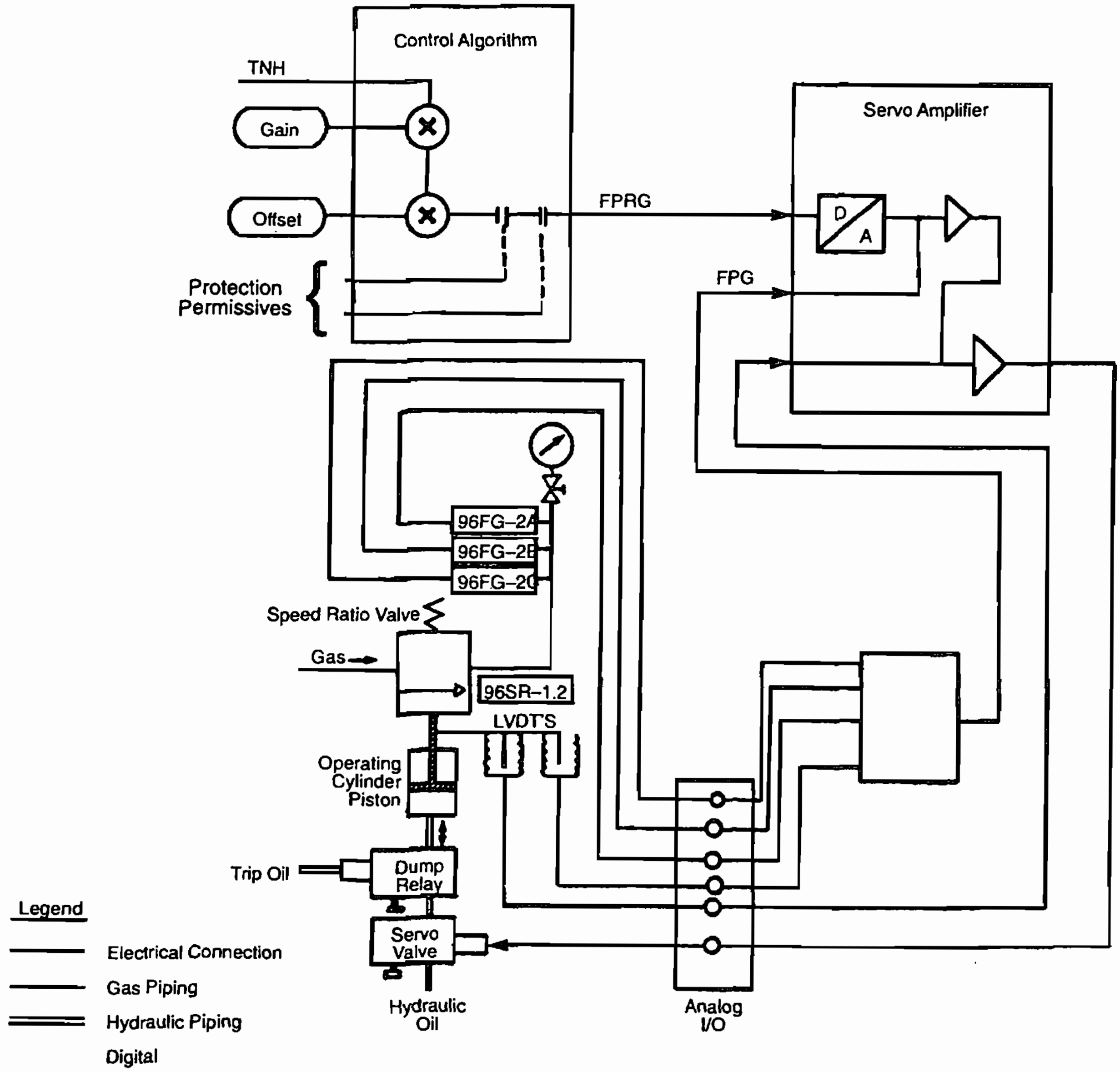

Figure 3. Speed Ratio/Stop Valve Control Schematic.

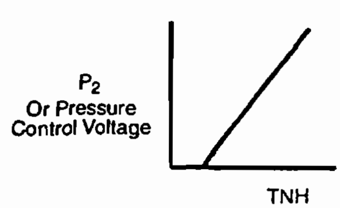

Figure 4. Speed Ratio Valve Pressure Calibration.

ATTACHMENT DCEP-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

Starting System

I. GAS TURBINE STATIC START SYSTEM

A. System Function and Design Requirements

Power for startup of the gas turbine is provided by the static start system. The static start system provides variable frequency voltage and current to the generator, in this way the generator serves as the starting motor required for starting the gas turbine. The static start system consists of the following major components:

1. Load Commutated Inverter (LCI)
2. Isolation Transformer
3. LCI Disconnect Switch
4. Slow Roll Motor (Turning Gear)

The turning gear provides the power necessary to breakaway and rotate the turbine prior to turbine start and also to rotate the shafting after turbine shutdown to avoid deformation of its shafting.

The turning gear system consists of an induction motor, reduction gears, SSS clutch, electrical isolation, and flexible coupling.

The turning gear will breakaway the turbine and slow roll at 5 to 7 rpm. In the event of power failure the turning gear is equipped with a feature for manual turning of the rotor system.

Lubricating oil for the reduction gears is self–contained. Lubrication of the SSS clutch and output shaft bearings requires continuous oil supply from the main lube oil system.

The SSS clutch is a positive tooth type overrunning clutch which is self-engaging in the breakaway or turning mode and overruns whenever the turbine/generator shafting exceeds the turning gear drive speed.

The insulated flexible coupling allows for angular and parallel misalignment as well as allowing for generator shaft axial expansion.

B. Operation

On a start signal, the lift oil pumps are started to lift the stationary rotor off of the bearing surfaces. The bearing pressure lift system must be operating prior to energizing the turning gear. This significantly reduces the amount of starting and break–away torque required for the machines and minimizes bearing damage during startup. Breakaway of the rotor system is accomplished by energizing the turning gear induction motor. A double reduction worm gear reducer is furnished with a hollow shaft in which the SSS clutch is mounted. Automatic engagement of the SSS clutch provides direct power transmission to the rotor system. The turning gear will rotate the rotor system to 5 to 7 rpm. As the static starter begins the starting sequence and accelerates the rotor the SSS clutch will automatically disengage the turning gear from the turbine rotor.

The static starter will begin operation in the "pulsed" mode, changing to the "load commutated" mode as soon as possible. The static starter will supply the variable frequency stator (armature) current required by the generator to operate as a synchronous motor and drive the gas turbine. The static starter will control the excitation system during static starting to regulate the field (rotor) current as required to maintain the required flux and generator voltage. The static start system operates to accelerate the turbine to 25 to 30 percent of rated speed to purge the system for several minutes. At the end of the purge period the LCI removes power from the generator allowing the unit to coast down to approximately 15% speed and the turbine is fired and then accelerated to a self sustaining speed of about 90%. The static starter currents will be reduced as required until the starting means is no longer required. After self sustaining speed is accomplished the control system will load and synchronize the gas turbine generator. Operation of the neutral ground and stator disconnect switches is automatically controlled during the starting process.

Upon turbine shutdown, as the turbine decelerates to below turning gear speed (5 to 7 rpm), the SSS clutch engages if the turning motor is energized to provide slow roll rotor cooldown. This cooldown continues until proper gas turbine wheelspace temperatures drop to ambient.

In the event of a power outage when rotor turning is required, a manual turning assembly is provided to turn the rotor. This manual turning feature can also be used for borescope inspection of the gas turbine.

The turning gear system is sized to provide breakaway of the shafting system with the bearing pressure lift system operating on both the gas turbine and generator for manual and motor turning of the rotor train.

C. Operating Precautions

*** * * WARNING * * ***

This equipment contains a potential hazard of electric shock or burn. Only personnel who are adequately trained and thoroughly familiar with the equipment and the instructions should install, operate, or maintain this equipment.

Isolation of test equipment from the equipment under test presents potential electrical hazards. If the test equipment cannot be grounded to the equipment under test, the test equipment's case must be shielded to prevent contact by personnel.

To minimize hazard of electrical shock or burn, approved grounding practices and procedures must be strictly followed.

ATTACHMENT DCEP-EU1-I5

OPERATION AND MAINTENANCE PLAN

GE Power Systems
Gas Turbine

Unit Operation/Turbine (Gas)

(Applicability MS7001FA, 9001FA)

I. REFERENCE DATA AND PRECAUTIONS

A. Operator Responsibility

It is essential that the turbine operators be familiar with the information contained in the following operation text, the Control Specification drawings (consult the Control System Settings drawing for the index of Control Specification drawings), the Piping Schematic drawings including the Device Summary (consult the Control System Settings Drawing for the index by model list and drawing number of applicable schematics), the SPEEDTRONIC® control sequence program and the SPEEDTRONIC® Users' Manual. The operator must also be aware of the power plant devices which are tied into the gas turbine mechanically and electrically and could affect normal operation. No starts should be attempted whether on a new turbine or a newly overhauled turbine until the following conditions have been met:

1. Requirements listed under CHECKS PRIOR TO OPERATION have been met.
2. Control systems have been functionally checked for proper operation before restarting.
3. All GENERAL OPERATING PRECAUTIONS have been noted.

It is extremely important that gas turbine operators establish proper operating practices. We emphasize adherence to the following:

1. Respond to Annunciator Indicators — Investigate and correct the cause of the abnormal condition. This is particularly true for the protection systems, such as low oil pressure, overtemperature, vibration, overspeed etc.
2. Check of Control Systems — After any type of control maintenance is completed, whether repair or replacement of parts, functionally check control systems for proper operation. This should be done prior to restart of the turbine. It should not be assumed that reassembly, "as taken apart" is adequate without the functional test.
3. Monitor Exhaust Temperature During All Phases of Startup — The operator is alerted to the following:

CAUTION

Overtemperature can damage the turbine hot gas path parts.

Monitor exhaust temperature for proper control upon first startup and after any turbine maintenance is performed. Trip the turbine if the exhaust temperature exceeds the normal trip level, or increases at an unusual rate. A particularly critical period for overtemperature damage to occur is during the startup phase before the turbine reaches governing speed. At this time air flow is low and the turbine is unable to accelerate away from excess fuel.

B. General Operating Precautions

1. Temperature Limits

Refer to the Control Specifications for actual exhaust temperature control settings. It is important to define a "baseline value" of exhaust temperature spread with which to compare future data. This baseline data is established during steady state operation after each of the following conditions:

a. Initial startup of unit

b. Before and after a planned shut-down

c. Before and after planned maintenance

An important point regarding the evaluation of exhaust temperature spreads is not necessarily the magnitude of the spread, but the change in spread over a period of time. The accurate recording and plotting of exhaust temperatures daily can indicate a developing problem. Consult Control Specification-Settings Drawings for maximum allowable temperature spreads and wheelspace temperature operating limits.

The wheelspace thermocouples, identified together with their nomenclature, are on the Device Summary. A bad thermocouple will cause a "High Wheelspace Differential Temperature" alarm. The faulty thermocouple should be replaced at the earliest convenience.

When the average temperature in any wheelspace is higher then the temperature limit set forth in the table, it is an indication of trouble. High wheelspace temperature may be caused by any of the following faults:

1. Restriction in cooling air lines
2. Wear of turbine seals
3. Excessive distortion of the turbine stator
4. Improper positioning of thermocouple
5. Malfunctioning combustion system
6. Leakage in external piping
7. Excessive distortion of exhaust inner diffuser

Check wheelspace temperatures very closely on initial startup. If consistently high, and a check of the external cooling air circuits reveals nothing, it is permissible to increase the size of the cooling air orifices slightly. Consult with a General Electric Company field representative to obtain recommendations as to the size that an orifice should be increased. After a turbine overhaul, all orifices should be changed back to their original size, assuming that all turbine clearances are returned to normal and all leakage paths are corrected.

CAUTION

> Wheelspace temperatures are read on the operators interface. Temperatures in excess of the maximum are potentially harmful to turbine hot-gas-path parts over a prolonged period of time. Excessive temperatures are annunciated but will not cause the turbine to trip. High wheelspace temperature readings must be reported to the General Electric technical representative as soon as possible.

2. **Pressure Limits**

Refer to the Device Summary for actual pressure switch settings. Lube oil pressure in the bearing feed header is a nominal value of 25 psig. The turbine will trip at 8 psig. Pressure variations between these values will result from entrapped particulate matter within the lube oil filtering system.

3. **Vibration Limits**

The maximum overall vibration velocity of the gas turbine should never exceed 1.0 inch (2.54 cm) per second in either the vertical or horizontal direction. Corrective action should be initiated when the vibration levels exceed 0.5 inch (1.27 cm) per second as indicated on the control system <I>/HMI.

If doubt exists regarding the accuracy of the reading or if more accurate and specific vibration readings are desired a vibration check is recommended using vibration test equipment.

4. **Load Limit**

The maximum load capability of the gas turbine is given in the control specification. For the upper limits of generator capability, refer to the Reactive Capability Curve following the GENERATOR tab.

5. **Overloading of Gas Turbine, Facts Involved and Policy**

It is General Electric practice to design gas turbines with margins of safety to meet the contract commitments and to secure long life and trouble-free operation.

So that maximum trouble-free operation can be secured, General Electric designs these machines with more than ample margins on turbine bucket thermal and dynamic stresses, compressor and turbine wheel stresses, generator ventilation, coolers, etc. As a result, these machines are designed somewhat better than is strictly necessary, because of the importance of reliability of these turbines to our customers and to the electrical industry.

It cannot be said, therefore, that these machines cannot be safely operated beyond the load limits. Such operation, however, always encroaches upon the design margins of the machines with a consequent reduction in reliability and increased maintenance. Accordingly, any malfunction that occurs as a result of operation beyond contract limits cannot be the responsibility of the General Electric Company.

The fact that a generator operates at temperature rises below the 185°F (85°C) for the rotor and 140°F (60°C) for the stator permitted by the AIEE Standards does not mean that it can be properly run with full safety up to these values by overloading beyond the nameplate rating. These standards were primarily set up for the protection of insulation from thermal deterioration on small machines. The imbedded temperature detectors of the stator register a lower temperature than the copper because of the temperature drop through the insulation from the copper to the outside of the insulation, where the temperature detectors are located. There are also conditions of conductor expansion, insulation stress, etc., which impose limitations. These factors have been anticipated in the "Vee" curves and reactive capability curves which indicate recommended values consistent with good operating practice. The "Vee" curves and reactive capability curves form part of the operating instructions for the generator and it is considered unwise to exceed the values given.

The gas turbines are mechanically designed so that (within prescribed limits), advantage can be taken of the increased capability over nameplate rating, which is available at lower ambient temperatures (because of increased air density), without exceeding the maximum allowable turbine inlet temperature.

The load limit of the gas turbine–generator must not be exceeded, even when the ambient temperature is lower than that at which the load limit of the gas turbine is reached. Under these conditions, the gas turbine will operate at this load with a lower turbine inlet temperature and the design stresses on the load coupling and turbine shaft will not be exceeded.

If the turbine is overloaded so that the turbine exhaust temperature schedule is not followed for reasons of malfunctioning or improper setting of the exhaust temperature control system, the maximum allowable turbine inlet temperature or the maximum allowable exhaust temperature, or both, will be exceeded and will result in a corresponding increase in maintenance and, in extreme cases, might result in failure of the turbine parts.

The exhaust temperature control system senses the turbine exhaust temperature and introduces proper bias to limit the fuel flow so that neither the maximum allowable turbine inlet temperature nor the maximum allowable turbine exhaust temperature is exceeded.

6. Fire Protection System Operating Precautions

The fire protection system, when actuated, will cause several functions to occur in addition to actuating the media discharge system. The turbine will trip, an audible alarm will sound, and the alarm message will be displayed on the <I>/HMI. The ventilation openings in the compartments will be closed by a pressure-operated latch and the damper in the turbine shell cooling discharge will be actuated.

The annunciator audible alarm may be silenced by clicking on the alarm SILENCE target. The alarm message can be cleared from the ALARM list on the <I>/HMI after the ACKNOWLEDGE target and the ALARM RESET target are actuated, but only after the situation causing the alarm has been corrected.

The fire protection system *must be replenished and reset* before it can automatically react to another fire. Reset must be made after each activation of the fire protection system which includes an initial discharge followed by an extended discharge period of the fire protection media.

Fire protection system reset is accomplished by resetting the pressure switch located on the fire protection system.

Ventilation dampers, automatically closed by a signal received from the fire protection system, must be reopened manually in all compartments before restarting the turbine.

CAUTION

> Failure to reopen compartment ventilation dampers will severely shorten the service life of major accessory equipment. Failure to reopen the load coupling compartment dampers will materially reduce the performance of the generator.

7. Combustion System Operating Precautions

WARNING

Sudden emission of black smoke may indicate a possibility of outer casing failure or other serious combustion problems. In such an event:

C. Immediately shut down the turbine.

D. Allow no personnel inside the turbine compartment until turbine is shut down.

E. Caution all personnel against standing in front of access door openings into pressurized compartments.

F. Perform a complete combustion system inspection.

G. To reduce the possibility of combustion outer casing failure, the operator should adhere to the following:

H. During operation, exhaust temperatures are monitored by the SPEEDTRONIC® control system. The temperature spread is compared to allowable spreads with alarms and/or protective trips resulting if the allowable spread limits are exceeded.

I. After a trip from 75% load or above, observe the exhaust on startup for black or abnormal smoke and scan the exhaust thermocouples for unusually high spreads. Record temperature spread during a normal startup to obtain base line signature for comparison. Excessive tripping should be investigated and eliminated.

K. Adhere to recommended inspection intervals on combustion liners, transition pieces and fuel nozzles.

Operating a turbine with non-operational exhaust thermocouples increases the risk of turbine overfiring and prevents diagnosis of combustion problems by use of temperature differential readings.

To prevent the above described malfunctions the operator should keep the number of non-operational exhaust thermocouples to a maximum of two but no more than *one* of any three adjacent thermocouples.

CAUTION

> Operation of the gas turbine with a single faulty thermocouple should not be neglected, as even one faulty thermocouple will increase the risk of an invalid "combustion alarm" and/or "Trip". The unit should not be shut down just for replacement of a single faulty thermocouple. However, every effort should be made to replace the faulty thermocouples when the machine is down for any reason.

Adherence to the above criteria and early preventive maintenance should reduce distortions of the control and protection functions and the number of unnecessary turbine trips.

1. Cooldown/Shutdown Precautions

CAUTION

> In the event of an emergency shutdown in which internal damage of any rotating equipment is suspected, do not turn the rotor after shutdown. Maintain lube oil pump operation, since lack of circulating lube oil following a hot shutdown will result in rising bearing temperatures which can result in damaged bearing surfaces. If the malfunction that caused the shutdown can be quickly repaired, or if a check reveals no internal damage affecting the rotating parts, reinstate the cooldown cycle.

If there is an emergency shutdown and the turbine is not turned with the rotor turning device, the following factors should be noted:

a. Within 20 minutes, maximum, following turbine shutdown, the gas turbine may be started without cooldown rotation. Use the normal starting procedure.

b. Between 20 minutes and 48 hours after shutdown a restart should not be attempted unless the gas turbine rotor has been turned from one to two hours.

c. If the unit has been shut down and not turned at all, it must be shut down for approximately 48 hours before it can be restarted without danger of shaft bow.

CAUTION

> Where the gas turbine has not been on rotor turning operation after shutdown and a restart is attempted, as under conditions (a) and (b) above, the operator should maintain a constant check on vibration velocity as the unit is brought up to its rated speed. If the vibration velocity exceeds one inch per second at any speed, the unit should be shut down and the shaft rotated for at least one hour before a second starting attempt is made. If seizure occurs during the turning operation of the gas turbine, the turbine should be shut down and remain idle for at least 30 hours, or until the rotor is free. The turbine may be rotated at any time during the 30-hour period if it is free; however, audible checks should be made for rubs.

NOTE

The vibration velocity must be measured at points near the gas turbine bearing caps.

II. PREPARATIONS FOR NORMAL LOAD OPERATION

A. Standby Power Requirements

Standby AC power insures the immediate startup capability of particular turbine equipment and related control systems when the start signal is given. Functions identified by asterisk are also necessary for unit environmental protection and should not be turned off except for maintenance work on that particular function. Standby AC power is required for:

1. Lube oil heaters, which when used in conjunction with the lube oil pumps, heat and circulate turbine lube oil at low ambient temperatures to maintain proper oil viscosity.

2. *Control panel heating.

3. *Generator heating.

4. Lube oil pumps. Auxiliary pump should be run at periodic intervals to prevent rust formation in the lube oil system.

5. Fuel oil heaters, where used. These heaters used in conjunction with the fuel oil pumps, heat and circulate fuel oil at low ambient temperatures to maintain proper fuel oil viscosity.

6. Compartment heating.

7. *Operation of control compartment air conditioner during periods of high ambient temperature to maintain electrical equipment insulation within design temperature limits.

8. *Battery charging (where applicable).

B. Checks Prior to Operation

The following checks are to be made before attempting to operate a new turbine or an overhauled turbine. It is assumed that the turbine has been assembled correctly, is in alignment and that calibration of the SPEEDTRONIC® system has been performed per the Control Specifications. A standby inspection of the turbine should be performed with the lube oil pump operating and emphasis on the following areas:

1. Check that all piping and turbine connections are securely fastened and that all blinds have been removed. Most tube fittings incorporate a stop collar which insures proper torquing of the fittings at initial fitting make up and at reassembly. These collars fit between the body of the fitting and the nut and contact in tightening of the fitting. The stop collar is similar to a washer and can be rotated freely on unassembled fittings. During initial assembly of a fitting with a stop collar, tighten the nut until it bottoms on the collar. The fitting has to be sufficiently tightened until the collar cannot be rotated by hand. This is the inspection for a proper fitting assembly. For each remake of the fitting, the nut should again be tightened until the collar cannot be rotated.

2. Inlet and exhaust plenums and associated ducting are clean and rid of all foreign objects. All access doors are secure.

3. Where fuel, air or lube oil filters have been replaced check that all covers are intact and tight.

4. Verify that the lube oil tank is within the operating level and if the tank has been drained that it has been refilled with the recommended quality and quantity of lube oil. If lube oil flushing has been conducted verify that all filters have been replaced and any blinds if used, removed.

5. Check operation of auxiliary and emergency equipment, such as lube oil pumps, water pumps, fuel forwarding pumps, etc. Check for obvious leakage, abnormal vibration (maximum 3 mils), noise or overheating.

6. Check lube oil piping for obvious leakage. Also using provided oil flow sights, check visually that oil is flowing from the bearing drains. The turbine should not be started unless flow is visible at each flow sight.

7. Check condition of all thermocouples and/or resistance temperature detectors (RTDs) on the <I>/HMI. Reading should be approximately ambient temperature.

8. Check spark plugs for proper arcing.

WARNING

Do not test spark plugs where explosive atmosphere is present.

If the arc occurs anywhere other than directly across the gap at the tips of the electrodes, or if by blowing on the arc it can be moved from this point, the plug should be cleaned and the tip clearance adjusted. If necessary, the plug should be replaced. Verify the retracting piston for free operation.

9. Devices requiring manual lubrication are to be properly serviced.

10. Determine that the cooling water system has been properly flushed and filled with the recommended coolant. Any fine powdery rust, which might form in the piping during short time exposure to atmosphere, can be tolerated. If there is evidence of a scaly rust, the cooling system should be power flushed until all scale is removed. If it is necessary to use a chemical cleaner, most automobile cooling system cleaners are acceptable and will not damage the carbon and rubber parts of the pump mechanical seals or rubber parts in the piping.

Refer to "Cooling Water Recommendations for Combustion Gas Turbine Closed Cooling Systems" included under tab titled Fluid Specifications. Note the following regarding antifreeze.

CAUTION

Do not change from one type antifreeze to another without first flushing the cooling system very thoroughly. Inhibitors used may not be compatible and can cause formation of gums, in addition to destroying effectiveness as an inhibitor. Consult the antifreeze vendor for specific recommendations.

Following the water system refill ensure that water system piping, primarily pumps and flexible couplings, do not leak. It is wise not to add any corrosion inhibitors until after the water system is found to be leak free.

1. The Load Commutator Inverter (LCI) should be calibrated and tested as per GEH–6192.

2. The use of radio transmitting equipment in the vicinity of open control panels is not recommended. Prohibiting such use will assure that no extraneous signals are introduced into the control system that might influence the normal operation of the equipment.

3. Check the Cooling and Sealing Air Piping against the assembly drawing and piping schematic, to ensure that all orifice plates are of designated size and in designated positions.

4. At this time all annunciated ground faults should be cleared. It is recommended that units not be operated when a ground fault is indicated. Immediate action should be taken to locate all grounds and correct the problems.

C. Checks During Start Up and Initial Operation

The following is a list of important checks to be made on a new or newly overhauled turbine with the OPERATION SELECTOR switch in various modes. The Control Specifications — Control Systems Adjustments should be reviewed prior to operating the turbine.

CAUTION

> Where an electric motor is used as the starting means refer to the Control Specifications for maximum operating time.

When a unit has been overhauled those parts or components that have been removed and taken apart for inspection/repair should be critically monitored during unit startup and operation. This inspection should include: leakage check, vibration, unusual noise, overheating, lubrication.

1. Crank

a. Listen for rubbing noises in the turbine compartment especially in the load tunnel area. A sound-scope or some other listening type device is suggested. Shutdown and investigate if unusual noise occurs.

b. Check for unusual vibration.

c. Inspect for water system leakage.

2. Fire

*** WARNING ***

Due to the complexity of gas turbine fuel systems, it is imperative for everyone to exercise extreme caution in and near any turbine compartment, fuel handling system, or any other enclosures or areas containing fuel piping or fuel system components.

Do not enter the turbine compartment unless absolutely necessary. When it is necessary, exercise caution when opening and entering the compartment. Be aware of the possibility of fuel leaks, and be prepared to shut down the turbine and take action if a leak is discovered.

At any time, if/when entering the turbine compartment or when in the vicinity of the fuel handling system or other locations with fuel piping, fuel system components, or fuel system connections, while the turbine is operating, implement the following:

Conduct an environmental evaluation of the turbine compartment, fuel handling system, or specific area. Pay particular attention to all locations where fuel piping/components/connections exist.

Follow applicable procedures for leak testing. If fuel leaks are discovered, exit the area quickly, shut the turbine down, and take appropriate actions to eliminate the leak(s).

Require personnel entering the turbine compartment to be fitted with the appropriate personal protective equipment, i.e., hard hat, safety glasses, hearing protection, harness/manline (optional depending on space constraints), heat resistant/flame retardant coveralls and gloves.

Establish an attendant to maintain visual contact with personnel inside the turbine compartment and radio communications with the control room operator.

During the first start-up after a disassembly, visually check all connections for fuel leaks. Preferably check the fittings during the warm-up period when pressures are low. Visually inspect the fittings again at full speed, no load, and at full load. Do not attempt to correct leakage problems by tightening fittings and/or bolting while lines are fully pressurized. Note area in question and, depending on severity of leak, repair at next shutdown, or if required shut unit down immediately. Attempts to correct leakage problem on pressurized lines could lead to sudden and complete failure of component and resulting damage to equipment and personnel injury.

a. Bleed fuel oil filters, if appropriate. Then check entire fuel system and the area immediately around the fuel nozzle for leaks. In particular check for leaks at the following points:

Turbine Compartment

(1) Fuel piping/tubing to fuel nozzle

(2) Fuel check valves

(3) Atomizing air manifold and associated piping (when used)

(4) Gas manifold and associated piping (when used)

Accessory Module

(1) Flow divider (when used)

(2) Fuel and water pumps

(3) Filter covers and drains

CAUTION

Elimination of fuel leakage in the turbine compartment is of extreme importance as a fire preventive measure.

b. Monitor FLAME status on the <I> processor to verify all flame detectors are correctly indicating flame.

c. Monitor the turbine control system readings on the <I> processor for unusual exhaust thermocouple temperature, wheelspace temperature, lube oil drain temperature, highest to lowest exhaust temperature spreads and "hot spots" i.e. combustion chamber(s) burning hotter than all the others.

d. Listen for unusual noises and rubbing.

e. Monitor for excessive vibration.

3. Automatic, Remote

On initial startup, permit the gas turbine to operate for a 30 to 60 minute period in a full speed, no load condition. This time period allows for uniform and stabilized heating of the parts and fluids. Tests and checks listed below are to supplement those recorded in Control Specification — Control System Adjustments. Record all data for future comparison and investigation.

a. Continue monitoring for unusual rubbing noises and shutdown immediately if noise persists.

b. Monitor lube oil tank, header and bearing drain temperatures continually during the heating period. Refer to the Schematic Piping Diagram — Summary Sheets for temperature guidelines. Adjust VTRs if required.

c. At this time a thorough vibration check is recommended, using vibration test equipment such as IRD equipment (IRD Mechanalysis, Inc.) or equivalent with filtered or unfiltered readings. It is suggested that horizontal, vertical and axial data be recorded for the:

(1) all accessible bearing covers on the turbine

(2) turbine forward compressor casing

(3) turbine support legs

(4) bearing covers on the load equipment

d. Check wheelspace, exhaust and control thermocouples for proper indication on the <I>/HMI. Record these values for future reference.

e. Flame detector operation should be tested per the Control Specification — Control System Adjustments.

f. Utilize all planned shutdowns in testing the Electronic and Mechanical Overspeed Trip System per the Control Specifications — Control System Adjustments. Refer to Special Operations section of this text.

g. Monitor <I>/HMI display data for proper operation.

III. OPERATING PROCEDURES

A. General

The following instructions pertain to the operation of a model series 7001FA or 9001FA gas turbine unit designed for generator drive application. These instructions are based on use of SPEEDTRONIC® turbine control panels.

Functional description of the <I>/HMI Main Display follows; however, panel installation, calibration, and maintenance are not included.

Operational information includes startup and shutdown sequencing in the AUTO mode of operation. The most common causes of alarm messages can be found in the concluding section.

It is not intended to cover initial turbine operation herein; rather, it will be assumed that initial startup, calibration and checkouts have been completed. The turbine is in the cooldown or standby mode ready for normal operation with AC and DC power available for all pumps, motors, heaters, and controls and all annunciator drops are cleared.

Refer to the Control Specifications (Control and Protection Systems) in this volume, and the previously furnished Control Sequence Program (CSP) for additional operating sequence information and related diagrams.

B. Start-Up

1. General

Operation of a single turbine/generator unit may be accomplished either locally or remotely.

The following description lists operator, control system and machine actions or events in starting the gas turbine.

Reference the section "Description of Panels and Terms — Turbine Control Panel" for description of turbine panel devices. The following assumes that the unit is off of cooldown, and in a ready to start condition.

2. Starting Procedure

a. Using the cursor positioning device, select "MAIN" display from the DEMAND DISPLAY menu.

(1) The display will indicate speed, temperature, various conditions etc. Three lines displayed on the <I> /HMI will read:

SHUTDOWN STATUS
OFF COOLDOWN
OFF

b. Select "AUTO" and "EXECUTE"

(1) The <I>/HMI display will change to:

STARTUP STATUS
READY TO START
AUTO

c. Select "START" and "EXECUTE"

(1) Unit auxiliaries will be started including a motor driven lube oil pump used to establish lube oil pressure. The <I>/HMI message SEQ IN PROGRESS will appear.

(2) When permissives are satisfied, the master protective logic (L4) will be satisfied. The <I>/HMI display will change to:

STARTUP STATUS
STARTING
AUTO; START

(3) The turbine shaft will begin to rotate on turning gear. The zero speed signal "14HR" will be displayed. When the unit reaches approximately 6 rpm, the starting device will be energized and accelerate the unit. The <I> /HMI display will change to START-UP STATUS/CRANKING.

(4) When the unit reaches approximately 15% speed, the minimum speed signal "14HM" will be displayed on the <I>/HMI. (For machines with cooling water fan motors receiving power from the generator terminals via the UCAT transformer, field flashing will be initiated to build up generator voltage to power the fans; otherwise, field flashing to build up generator voltage will occur at operating speed.)

(5) If the unit configuration requires purging of the gas path prior to ignition, the starting device will crank the gas turbine at purge speed for a period of time determined by the setting of the purge timer. See Control Specifications-Settings Drawing for purge timer settings.

(6) FSR will be set to firing value. (FSR, Fuel Stroke Reference, is the electrical signal that determines the amount of fuel delivered to the turbine combustion system.) Ignition sequence is initiated. The <I>/HMI display will change to START UP STATUS/FIRING.

(7) When flame is established, the <I>/HMI display will indicate flame in those combustors equipped with flame detectors.

(8) FSR is set back to warm-up value, and the <I> /HMI display will indicate STARTUP STATUS/WARMING UP. If the flame goes out during the 60 second firing period, FSR will be reset to firing value. (At the end of the ignition period, if flame has not been established, the unit will remain at firing speed. Refer to operation 8 in the Special Operations section for specific operating instructions for DLN 2.0 and DLN 2.6 configured machines.) At this time the operator may shut the unit down or attempt to fire again. To fire again select CRANK on the Main Display. The purge timer and firing timer are reinitialized. The purge timer will begin to time. Reselecting AUTO will cause the ignition sequence to repeat itself after the purge timer has timed out. If the unit is being operated remotely and multiple starts capability exists (REMOTE having previously been selected on the Main Display), and no fire has been established at the end of the ignition period, the unit will be purged of unburned fuel. At the end of the purge period ignition will be attempted again. If flame is not established at this time, the starting sequence will be terminated and the unit will shutdown.

At the end of the warmup period, with flame established, FSR will begin increasing. The <I>/HMI will indicate STARTUP STATUS/ACCELERATING and the turbine will increase in speed. At approximately 50% speed, the accelerating speed signal "14HA" will be displayed on the <I> /HMI.

(9) The turbine will continue to accelerate. When it reaches 85–90% speed, the starting device will disengage and shutdown. The <I>/HMI will indicate the change in status from STARTUP CONTROL to SPEED CONTROL at approximately 60% speed.

(10) When the turbine reaches operating speed, the operating speed signal "14HS" will be displayed on the <I>/HMI. Field flashing is terminated. If the synchronizing selector switch (43S) on the generator control panel is in the OFF position and REMOTE is not selected on the <I>/HMI, as the turbine reaches operating speed, <I> /HMI will now read:

RUN STATUS
FULL SPEED NO LOAD
AUTO; START

If the synchronizing selector switch on the generator panel is in the AUTO position or REMOTE is selected on the <I>/HMI automatic synchronizing is initiated. The <I>/HMI will read SYNCHRONIZING.

The turbine speed is matched to the system (to less than 1/3 Hz difference) and when the proper phase relationship is achieved the generator breaker will close. The machine will load to Spinning Reserve unless a load control point BASE, PEAK or PRESELECTED LOAD has been selected.

The <I>/HMI will display SPINNING RESERVE, once the unit has reached this load point.

C. Synchronizing

When a gas turbine-driven synchronous generator is connected into a power transmission system, the phase angle of the generator going on-line must correspond to the phase angle of the existing line voltage at the moment of its introduction into the system. This is called synchronizing.

CAUTION

> Before initiating synchronization procedures, be sure that all synchronization equipment is functioning properly, and that the phase sequence of the incoming unit corresponds to the existing line phase sequence and the potential transformers are connected correctly to proper phases. Initial synchronization and checkout after performing maintenance to synchronizing equipment should be performed with the breaker racked out.

NOTE

Synchronizing cannot take place unless AUTO or REMOTE has been selected on the <I>/HMI Main Display and the turbine has reached full speed.

Generator synchronization can be accomplished either automatically or manually. Manual synchronization is accomplished by the following procedure:

1. Place the synchronizing selector switch on the generator panel (43S) in the MANUAL position.
2. Select AUTO on the <I>/HMI Main Display.
3. Select START and EXECUTE on the <I>/HMI Main Display. This will start the turbine and accelerate it to full speed as previously described. At this point the CRT will indicate RUN STATUS, FULL SPEED NO LOAD.
4. Compare the generator voltage with the line voltage. (These voltmeters are located on the generator control panel.)
5. Make any necessary voltage adjustment by operating the RAISE- LOWER (90R4) switch on the generator panel until the generator voltage equals the line voltage.
6. Compare the generator and line frequency on the synchroscope (located on the generator control panel). If the pointer is rotating counterclockwise, the generator frequency is lower than the line frequency and should be raised by increasing the turbine-generator speed. The brightness of the synchronizing lights will change with the rotation of the synchroscope. When the lights are their dullest the synchroscope will be at the 12 o'clock position. The lights should not be used to synchronize but only to verify proper operation of the synchroscope.
7. Adjust the speed until the synchroscope rotates clockwise at approximately five seconds per revolution or slower.
8. The generator circuit breaker "close" signal should be given when it reaches a point approximately one minute before the 12 o'clock position. This allows for a time lag for the breaker contacts to close after receiving the close signal.

Automatic synchronization is accomplished by the following steps:

1. Place the synchronizing selector switch (43S) in the AUTO position.

2. Select AUTO on the <I>/HMI Main Display.

3. Select START on the <I>/HMI Main Display.

This procedure will start the turbine, and upon attainment of "complete sequence", match generator voltage to line voltage (if equipped with optional voltage matching), synchronize the generator to the line frequency, and load the generator to the preselected value. A "breaker closed" indicator will actuate when the generator circuit breaker has closed placing the synchronized unit on-line.

Once the generator has been connected to the power system, the turbine fuel flow may be increased to pick up load, and the generator excitation may be adjusted to obtain the desired KVAR value.

WARNING

Failure to synchronize properly may result in equipment damage and/or failure, or the creation of circumstances which could result in the automatic removal of generating capacity from the power system.

In those cases where out-of-phase breaker closures are not so serious as to cause immediate equipment failure or system disruption, cumulative damage may result to the on-coming generator. Repeated occurrences of out-of-phase breaker closures can eventually result in generator failure because of the stresses created at the time of closure.

Out-of-phase breaker closure of a magnitude sufficient to cause either immediate or cumulative equipment damage mentioned above will usually result in annunciator drops to notify the operator of the problem. The following alarms have been displayed at various occurrences of known generator breaker malclosures:

1. High vibration trip

2. Loss of excitation

3. Various AC undervoltage drops

Out-of-phase breaker closure will result in abnormal generator noise and vibration at the time of closure. If there is reason to suspect such breaker malclosure, the equipment should be immediately inspected to determine the cause of the malclosure and for any damage to the generator.

Refer to the "Control and Protection" section of this volume for additional information on the synchronizing system.

D. Normal Load Operation

1. Manual Loading

Manual loading is accomplished by clicking on the SPEED SP RAISE/SPEED SP LOWER targets on the <I>/HMI Main Display.

Manual loading can also be accomplished by means of the governor control switch (70R4/CS) on the generator control panel. Holding the switch to the right will increase the load; holding it to the left will decrease the load.

Manual loading beyond the selected temperature control point BASE or PEAK is not possible. The manual loading rate is shown in the Control Specification-Settings Drawing.

NOTE

When manually loading with the governor control switch (70R4/CS) for load changes greater than 25% of full load, the operator should not change more than 25% of full load in one minute.

2. Automatic Loading

On startup if no load point is selected, the unit will load to the SPINNING RESERVE load point. The SPINNING RESERVE load point is slightly greater than no load, typically 8% of base rating.

An intermediate load point, PRE-SELECTED load, and temperature control load points BASE and PEAK can be selected anytime after a start signal has been given. The selection will be displayed on the <I>/HMI. The unit will load to the selected load point. PRESELECTED LOAD is a load point greater than SPINNING RESERVE and less than BASE, typically 50%. The auto loading rate is shown in Control Specification-Settings Drawing.

E. Remote Operation

To transfer turbine control from the control compartment to remotely located equipment, select REMOTE on the <I>/HMI Main Display. The turbine may then be started, automatically synchronized, and loaded by the remote equipment.

If manual synchronization is to be performed at the remote location, the synchronizing selector switch (43S) mounted on the generator control panel must be placed in the OFF/REMOTE position.

F. Shutdown and Cooldown

1. Normal Shutdown

Normal shutdown is initiated by selecting STOP on the <I>/HMI Main Display. The shutdown procedure will follow automatically through generator unloading, turbine speed reduction, fuel shutoff at part speed and initiation of the cooldown sequence as the unit comes to rest.

2. Emergency Shutdown

Emergency shutdown is initiated by depressing the EMERGENCY STOP pushbutton. Cooldown operation after emergency shutdown is also automatic provided the permissives for this operation are met.

3. Cooldown

Immediately following a shutdown, after the turbine has been in the fired mode, the rotor is turned to provide uniform cooling. Uniform cooling of the turbine rotor prevents rotor bowing, resultant rubbing and imbalance, and related damage that might otherwise occur when subsequent starts are attempted without cooldown. The turbine can be started and loaded at any time during the cooldown cycle.

The cooldown cycle may be accelerated using the starting device; in which case it will be operated at cranking speed.

A rotor turning device is provided for cooldown rotation. A description of rotor turning operation and servicing can be found in the Starting System tab.

The minimum time required for turbine cooldown depends mainly on the turbine ambient temperature. Other factors, such as wind direction and velocity in outdoor installations and air drafts in indoor installations, can have an affect on the time required for cooldown. The cooldown times recommended in the following paragraphs are the result of General Electric Company operating experience in both factory and field testing of General Electric gas turbines. The purchaser may find that these times can be modified as experience is gained in operation of the gas turbine under his particular site conditions.

Cooldown times should not be accelerated by opening up the turbine compartment doors or the lagging panels since uneven cooling of the outer casings may result in excessive stress.

The unit must be on rotor turning operation immediately following a shutdown for at least 24 hours to ensure minimum protection against rubs and unbalance on a subsequent starting attempt. The General Electric Company, however, recommends that the rotor turning operation continue for 48 hours after shutdown to ensure uniform rotor cooling.

G. Special Operations

1. Fuel Transfer (Gas-Distillate Option)

Fuel transfer is initiated using the Fuel Mixture Display on the <I>/HMI. When transferring from one fuel to the other, there is a thirty second delay before the transfer begins. For the gas-to-distillate transfer, the delay allows for filling the liquid fuel lines. For the distillate-to-gas transfer, the delay allows time for the speed ratio valve (and gas control valve) to modulate the inter volume gas pressure before the transfer begins. Once started, fuel transfer takes approximately thirty seconds. The transfer can be stopped at any fuel mixture proportion within limits as specified in the Control Specification-Settings Drawing by setting the FUEL MIX SETPOINT and then selecting MIX. Fuel transfer should be initiated prior to ignition or after the unit reaches operating speed.

2. Automatic Fuel Transfer On Low Gas Pressure (Gas-Distillate Option)

In the event of low fuel gas pressure the turbine will transfer to liquid fuel. The transfer will occur with no delay for line filling. To return to gas fuel operation after an automatic transfer, manually reselect gas fuel.

3. Testing the Emergency DC Lube Pump

The DC emergency pump may be tested using the test pushbutton on the motor starter.

4. Overspeed Trip Checks

Overspeed trip system testing should be performed on an annual basis on peaking and intermittently used gas turbines. On continuously operated units, the test should be performed at each scheduled shutdown and after each major overhaul. All units should be tested after an extended shutdown period of two or more months unless otherwise specified in the Control Specifications-Adjustments Drawing.

NOTE

The turbine should be operated for at least 30 minutes at rated speed before checking the overspeed settings.

Turbine speed is controlled by the turbine speed reference signal TNR. The maximum speed called for by TNR is limited by the high speed stop control constant. This value is nominally set at 107% of rated speed. It will be necessary to select the overspeed test function, which will reprogram the 107% setpoint to 113%, in order to allow the speed to increase above the electrical overspeed trip setting. With the high speed stop constant adjusted to be higher than the electrical overspeed trip speed, raise unit speed gradually by using the SPEED SP RAISE target on the <I> /HMI Main Display and observe speed at which the unit trips against the value tabulated in the Control Specifications — Setting drawing. Once the unit trips, the speed setpoint is returned to the 107% maximum value.

CAUTION

1. Do not exceed the maximum search speed as defined in the Control Specifications.
2. Return all constants to their normal value after coastdown of unit.

5. Steam Injection Operation (Optional)

Before operating the steam injection system for the first time following an overhaul or periods of extended shutdown, it is important that the following checks be made:

a. Steam supply is within design parameters

b. Instrument air supply is at required pressure

c. Steam line orifice size is correct

d. Pre-Operation Checks

Prior to operation, check for the following conditions:

e. <I>/HMI controls are in non-select positions (Steam Injection OFF)

f. Manual stop valve is open

g. All hand valves in line of flow are open

h. All valves to temperature or pressure gauges are open

i. Steam supply pressure and temperature are in operating range

j. Startup

The automatic control system, in conjunction with logic circuits of the microcomputer of the SPEEDTRONIC® control system, operates the steam injection system control valving and assures that the proper amount of steam injection is provided to the turbine combustion system during operation.

To initiate steam injection the operator must first select the Steam Injection Overview Display on the <I>/HMI. Selecting the STM INJ ON target initiates the steam injection control. At this point the automatic steam control circuits will take over, initiate the drain and stop valve sequences and control the system. When steam conditions are correct, the steam control valve releases steam into the combustion system at the proper steam-to-fuel flow ratio.

The startup and operating sequence of the steam injection system is described and explained in the Steam Injection control system text of the Control and Protection Tab.

k. Trouble Shooting

The purpose of the system is to provide steam to the turbine combustion system at the desired pressure, temperature and flow. If this does not happen, the following problems may be the cause:

(1) Steam supply exhausted

(2) Insufficient supply pressure

(3) Control valve closed

(4) Stop valve closed

The following should be checked:

(1) Adequate steam supply

(2) Check steam supply system

(3) Check control valve actuator and drain valve operation

(4) Check that instrument air supply pressure is sufficient and/or check solenoid control valve operation.

Alarm and shutdown conditions of the steam injection system are detected by a protection program built into Control Sequence Program. Alarm and trip indications are displayed on the <I>/HMI. An alarm condition is initiated by high or low pressure levels and by high or low temperatures. See Control Specifications for alarm and trip point values.

The computer program is designed to trip the steam stop valve and prevent steam flow if steam temperature becomes too high or too low. It can trip the system on temperature or pressure to protect against loss of superheat and carry over of condensate. Steam at too high a pressure can cause damage to valve stem packing and system seals. A steam injection trip only shuts down the steam injection system. It does not trip the turbine.

6. DLNx II SYSTEM OPERATION

a. General

The Dry Low Nox II control system regulates the distribution of fuel delivered to multi–nozzle combustors located around the gas turbine. This system stages the fuel through multiple modes of operation to attain the low emissions mode of **Premix**. DLN–2 has only one burning zone but multiple nozzles and manifolds.

b. Gas Fuel Operation

There are three basic modes for fuel distribution to the combustor:

(1) Primary

Fuel to primary manifold only

(2) Lean-Lean

Fuel to primary and tertiary manifolds

(3) Premix

In this mode, fuel is in both the secondary and tertiary manifolds. This is the low emission mode.

c. Valves

There are four main valves in DLN–2:

Primary Gas Control Valve (GCVP)

Secondary Gas Control Valve (GCVS)

Quaternary Gas Control Valve (GCVQ)

Premix Splitter Valve (PMSV)

The PMSV is used downstream of the secondary gas control valve. This valve controls the flow between 4 secondary nozzles and 1 tertiary nozzle (The tertiary nozzle is not used during Primary mode).

d. Startup and Load Sequence

The gas turbine will startup with fuel going to primary manifold only and will accelerate to 81% corrected speed. At this point fuel flow will be initiated into the tertiary manifold and Lean-Lean will be established. As the unit is loaded to approximately 60% load (with no Bleed Heat), or 40% load (with Bleed Heat) a transfer to Premix will be performed. When transferring to Premix, the primary gas control valve will close, the secondary gas control valve will open,and the

Premix splitter valve will modulate to control the flow between the tertiary and secondary nozzles. Once the Primary control valve is closed, the Primary Purge System wil open to purge the primary nozzles.

The sequence of events on an unload is as follows:

(1) Premix to Transfer Mode

(2) Premix Transfer to Lean-Lean

(3) Fired shutdown in Lean-Lean

The mode selection is performed automatically in the control system when the turbine is at the proper operating conditions.

These conditions must be met before startup; The following valves must be in the closed position:

Stop/Speed Ratio

Primary Control Valve (GCVP)

Secondary Control Valve (GCVS)

Quaternary Control Valve (GCVQ)

The Premix Splitter Valve (PMSV) should be at 100% split (no secondary flow).

Bleed Heat Valve closed (if applicable)

e. Inlet Guide Vane Operation (IGV)

The DLN–2 combustor emission performance is sensitive to changes in fuel to air ratio. The DLNx combustor was designed according to the airflow regulation scheme used with IGV Temperature Control. The IGVs should remain at a fixed minimum value from full speed no load until the turbine incrases load while on the exhaust temperature contro curve. The IGVs open from their minimum value as the turbine increases load while on the exhaust temperature control curve until they reach a maximum at Base Load.

IGV Temperature Control is defaulted to be "on", but the operator should always check this during startup. The only exception to this rule is when temperature matching is selected (see Temperature Matching below), or simple cycle IGV control is selected. Simple Cycle IGV control can be selected between breaker closer and 8 MW, or at Full open IGVs.

f. Inlet Heating

Operation of the gas turbine with reduced minimum IGV settings can be used to extend the Premix operating region to lower loads. Reducing the minimum IGV angle allows the combustor to operate near a constant firing temperature that is high enough to support Premix operation while maintaining a sufficient fuel to air ratio.

Inlet heating through the use of recirculated compressor discharge airflow is necessary when operating with reduced IGV angles in order to protect the turbine compressor. Inlet heating protects the turbine compressor from stall by relieving discharge pressure and by increasing the inlet air stream temperature. Also, inlet heating prevents ice formation due to increased pressure drop across the reduced IGV angle.

The inlet heating system regulates the compressor discharge bleed flow through a control vlave and into a manifold located in the compressor inlet air stream. The control valve varies the inlet air flow as a function of the IGV angle, compressor operating and ambient temperature.

g. Temperature Matching

Temperature matching is used when the gas turbine exhaust temperature is to be controlled to bring on a steam turbine. The operator must select temperature matching "on". Once selected, the turbine has to be loaded/unloaded to the matching window. Once the unit is in the matching window, the operator can enable matching. With temperature matching "ON", the Gas Turbine Exhaust temperature can be increased using the targets on the Temperature Matching Control Screen.

h. DLNx II Display Messages

The following display messages will appear on the control panel <I>/HMI in order to inform the operator of the current combustion mode of operation:

Primary Mode

Lean-Lean Mode

Secondary Prefill

Piloted Premix Mode

Premix Transfer Mode

Premix Steady State

Tertiary only FSNL Mode

7. Water Washing System Operation (Optional)

a. General

Water washing should be scheduled during a normal shutdown, if possible. This will allow enough time for the internal machine temperature to drop to the required levels for the washing. The time required to cool the machine can be shortened by maintaining the unit at crank speed. During this cooling of the turbine, the wash water is to be heated to the proper level.

b. Mandatory Precautions

Before water washing of the compressor begins, the turbine blading temperature must be low enough so that the water does not cause thermal shock.

CAUTION

The differential temperature between the wash water and the interstage wheelspace temperature must not be greater than 120°F (48.9°C) to prevent thermal shock to the hot gas parts. For wash water of 180°F (82.2°C), the maximum wheelspace temperature must be no greater than 300°F (148.9°C) as measured by the digital thermocouple readout system on the turbine control panel.

To reduce this difference, the wash water may be heated and the turbine kept on crank until the wheelspace temperatures drop to an acceptable level. The wheelspace temperatures are read in the control room on the <I>/HMI.

CAUTION

If, during operation, there has been an increase in exhaust temperature spread above the normal 15°F to 30°F (8.3°C to 16.6°C), the thermocouples in the exhaust plenum should be examined. If they are coated with ash, the ash should be removed.Radiation shields should also be checked.

If they are not radially oriented relative to the turbine, they should be repositioned per the appropriate drawing. If the thermocouples are coated with ash, or if the radiation shields are not properly oriented, a correct temperature reading will not be obtained.

If neither of the above conditions exists and there is no other explanation for the temperature spread, consult the General Electric Installation and Service Engineering representative.

WARNING

The water wash operation involves water under high pressure. Caution must be exercised to ensure the proper positioning of all valves during this operation. Since the water may also be hot, necessary precautions should be taken in handling valves, pipes, and potentially hot surfaces.

NOTE

Before water washing the compressor, inspect the inlet plenum and gas turbine bellmouth for large accumulations of atmospheric contaminants which could be washed into the compressor. These deposits can be removed by washing with a garden hose.

c. Water Wash Procedures

Refer to cleaning publication included in this section for details on procedure.

8. Unit Operation After Failure to Fire on Liquid Fuel (DLN 2.0 or DLN 2.6)

The following only applies to units with DLN 2.0 or DLN 2.6 combustion systems. After every failure to fire on oil, a STOP command should be given and the unit allowed to decelerate to 2% speed and operate there for at least 2 minutes before being restarted on gas or liquid fuel. Currently, this must be done manually. This operation allows excess liquid fuel to drain from liners.

IV. DESCRIPTION OF PANELS AND TERMS

A. Turbine Control Panel (TCP)

The turbine control panel contains the hardware and software required to operate the turbine. A front elevation view of the panel can be seen in the Hardware Description.

EMERGENCY STOP (5E) — This red pushbutton is located on the front of the TCP. Operation of this pushbutton immediately shuts off turbine fuel.

BACKUP OPERATOR INTERFACE (BOI) — This interactive display is mounted on the front of the TCP. All operator commands can be issued from this module. In addition, alarm management can be performed and turbine parameters can be monitored from the <BOI> (Mark V only).

B. <I>/HMI

The <I>/HMI is a personal computer that directly interfaces to the turbine control panel. This is the primary operator station. All operator commands can be issued from the <I>/HMI. Alarm management can be performed and turbine parameters can be monitored. With the proper password, editing can also be accomplished.

1. Main Display

Operator selector targets and master control selector targets can be actuated from the main display by using the cursor positioning device (CPD). Operator selector targets include:

OFF — Inhibits a start signal.

CRANK — With crank selected, a start signal will bring the machine to purge speed.

FIRE — With FIRE selected, a START signal will bring the machine to minimum speed and establish flame in the combustors. Selecting FIRE while the machine is on CRANK will initiate the firing sequence and establish flame in the combustors.

AUTO — With AUTO selected, a START signal will bring the machine to operating speed. Changing selections from FIRE to AUTO will allow the machine to accelerate to operating speed.

REMOTE — With REMOTE selected, control for the unit is transferred to the remote control equipment.

Master control selector targets include:

START — A START selection will cause the unit to start. With AUTO selected, the unit will load to the SPINNING RESERVE load point.

FAST START — A FAST START selection will cause the unit to start. With AUTO selected, the unit will load to the PRESELECTED load point. The machine will load at the manual loading rate.

STOP — A STOP selection will cause the unit to initiate a normal shutdown.

All operator selector switches and master control selector targets are green and are located on the right side of the display. All green targets are the AUTO/EXECUTE type, which means that the target must be selected with the CPD and then, within three seconds, the EXECUTE target at the bottom of the display must also be selected in order to actuate that command.

2. **Load Control Display**

Load selector targets can be actuated from the load control display by using the cursor positioning device (CPD). Load selector targets include:

PRESEL — Select the preselected load point.

BASE — Select base temperature control load point.

*PEAK — Select peak temperature control load point.

3. ***Fuel Mixture Display**

Fuel selector targets are used to select the desired fuel by using the cursor positioning device (CPD). Fuel selector targets include:

GAS SELECT — 100% gas fuel operation.

DIST SELECT — 100% distillate fuel operation.

MIX SELECT — Selecting MIX while on 100% single fuel will cause the machine to transfer to mixed fuel operation at a preset mixture (not applicable on DLN units).

4. ***Isochronous Setpoint Display**

Governor selector targets are used to select the desired type of speed control by using the cursor positioning device (CPD). Governor selector targets include:

DROOP SELECT — Used to select droop speed control.

ISOCH SELECT — Used to select isochronous speed control.

5. ***Inlet Guide Vane Control Display**

The inlet guide vane (IGV) temperature control targets are IGV TEMP CNTL ON and IGV TEMP CNTL OFF. The IGV AUTO target selects normal operation of the IGVs. The IGV MANUAL target allows the maximum IGV angle to be manually set by the operator (not normally used while on–line).

6. **Alarm Display**

This screen displays the current un–reset alarms, the time when each alarm occurred, the alarm drop number and a word description of the alarm. An "*" indicates that the alarm has not been acknowledged. The "*" disappears after the alarm has been acknowledged. For more information, see the Turbine Control System Users' Manual.

7. **Auxiliary Display**

COOLDOWN ON and COOLDOWN OFF can be selected from this display.

8. **Manual Reset Target**

Selecting the manual reset target resets the Master Reset Lockout function. This target must be selected so that the unit can be restarted following a trip.

C. Definition of Terms

SPINNING RESERVE — The minimum load control point based on generator output. The spinning reserve magnitude in MWs can be found in the control specifications (5–10% of rating is a typical value).

PRESELECTED LOAD — A load control point based on generator output. The preselected load point is adjustable within a range designated in the Control Specification. The preseelected load point is normally set below the base load point (50–60% of rating is a typical value).

BASE LOAD — This is the normal maximum loading for continuous turbine operation as determined by turbine exhaust temperature levels.

PEAK LOAD (Optional) — This is the maximum allowable output permitted for relatively long–duration, emergency power requirement situations consistent with acceptable turbine parts life. Peak loading duration is based on turbine exhaust temperature levels.

D. Generator Control Panel (Typical)

SYNCHRONIZING LAMPS — Rough indication of the speed and phase relationship between the generator and the bus.

FREQUENCY METER — Indicates generator frequency.

INCOMING VOLTMETER — Indicates generator voltage.

RUN VOLTMETER — Indicates bus voltage.

SYNCHROSCOPE — Indicates the phase relationship between the generator and bus voltage.

GENERATOR AMMETER — Indicates generator phase current. The phase current to be read is selected on the three position ammeter selector switch.

GENERATOR WATTMETER — Indicates the generator output in megawatts.

GENERATOR VARMETER — Indicates the generator reactive output in megavars.

EXCITER VOLTMETER — Indicates generator field voltage (if used).

GENERATOR FIELD AMMETER — Indicates generator field amperes (if used).

AMMETER SELECTOR SWITCH — See Generator Ammeter (above).

SYNCHRONIZING SELECTOR SWITCH (43S/CS) — Three position switch used to select the synchronizing mode.

Manual — Selects manual synchronizing mode. In this position the generator frequency and voltage, bus voltage, and phase relationship will be displayed to facilitate manual synchronizing.

Off/Remote — Used when the unit is being controlled from the remote control equipment.

Auto — Used for local automatic synchronizing.

VOLTMETER SWITCH (VS) — Used to select the phase of the bus voltage to be displayed on the run voltmeter.

VOLTAGE/VAR CONTROL SWITCH (90R4/CS) — Controls generator voltage when the unit is off the line, and controls voltage/vars when the machine is on the line. (Increase — Right; Decrease — Left; spring return to normal.)

GENERATOR BREAKER CONTROL SWITCH (52G/CS) — Used to open or close the generator breaker. The indicator lights above the switch indicate Open (Green) and Closed (Red).

NOTE

Using this switch, the generator breaker should be closed only when proper synchronizing techniques are used or when the system onto which the generator is being brought is not energized.

GENERATOR DIFFERENTIAL LOCK-OUT SWITCH (86G) — Manual reset lockout switch which operates in the event of a generator fault.

GOVERNOR RAISE/LOWER CONTROL SWITCH (70R4/CS) — Used to control turbine speed when the generator is off the line (i.e. for manual synchronizing); generator load when the generator is on the line; and frequency when the generator is running isolated and on DROOP speed control.

TRANSFORMER DIFFERENTIAL LOCK-OUT SWITCH (86T) — Manual reset lockout switch which operates in the event of a transformer fault.

WATTHOUR METER — Measures the watthour output of the generator.

E. Motor Control Center

The turbine is provided with a motor control center for the control of the electrical auxiliaries. The motor control center includes AC and DC distribution systems.

Motor controllers are used for auxiliaries such as motors and heaters. Each motor controller normally consists of a breaker, control power transformer, control circuit, power contactor, selector switch and indicator lights. The selector switch is normally left in AUTO. Each motor control center is also provided with AC and DC distribution panel boards with circuit breakers.

F. Supervisory Remote Equipment

Supervisory equipment is normally functionally the same as the equipment described in the cable connected master panel. However, it may differ somewhat in metering and indications. Refer to the supervisory manufacturer's instruction manual for details.

G. Annunciator System

Alarms are displayed on the <I>/HMI when the ALARM Display mode is selected. Before clearing an alarm, action should be taken to determine the cause and perform the necessary corrective action. The following is a list of annunciator messages along with suggested operator action.

NOTE

The alarm messages can be categorized as either "trip" or "alarm". The "trip" messages contain the word TRIP in the message. The "alarm" messages do not indicate TRIP. For those alarms associated with permissive to start and trip logics latched up through the MASTER RESET function, it will be necessary to call up the <I>/HMI Display with the Master Reset target in order to unlatch and clear these alarms.

ATTACHMENT DCEP-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

DeSoto County Generating Company, LLC - DeSoto County Energy Park

Facility ID No. 0270016

Desoto County

Final Permit No. 0270016-007-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting North Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/921-9533

Compliance Authority:

Department of Environmental Protection
Southwest District Office
13051 North Telecom Parkway
Temple Terrace, Florida 33637-0926
Telephone: 813/632-7600
Fax: 813/632-7665

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Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

Permittee:
DeSoto County Generating Company, LLC
3800 NE Roan Street
Arcadia, Florida 34266

Final Permit No. 0270016-007-AV
Facility ID No: 0270016
SIC No. 4911
Project: Title V Air Operation Permit Renewal

This permit is for the operation of the DeSoto County Generating Company, LLC – DeSoto County Energy Park. This facility is located at 2800 Northeast Roan Street, Arcadia, Desoto County; UTM Coordinates: Zone 17, 419.75 km East and 3011.5 km North; and, Latitude: 27° 13' 30" North and Longitude: 81° 48' 42" West.

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

Effective Date: January 1, 2008
Renewal Application Due Date: July 5, 2012
Expiration Date: December 31, 2012

Trina L. Vielhauer for

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/jfk/sa

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two, dual-fuel, nominal 170 megawatt General Electric model PG7241FA combustion turbine-electrical generators with evaporative inlet coolers, two 75-foot exhaust stacks, and one 1.5-million gallon fuel oil storage tank. The combustion turbine units can operate in simple cycle mode and intermittent duty mode. The units are equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

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

Based on the initial Title V permit application received June 25, 2007, this facility is *not* a major source of hazardous air pollutants (HAP).

Subsection B. Summary of Emissions Units (EU).

EU No.	Brief Description
001	One nominal 170 megawatt gas simple-cycle combustion turbine-electrical generator with evaporative inlet cooler.
002	One nominal 170 megawatt gas simple-cycle combustion turbine-electrical generator with evaporative inlet cooler.

Please reference the Permit No., Facility ID No., and appropriate Emissions Units ID Nos. on all correspondence, test report submittals, applications, etc.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. Appendices. The appendices identified in the table of contents are attached as an enforceable part of this permit unless otherwise indicated.

2. Prevention of Accidental Releases (Section 112(r) of CAA).
   a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to RMP Reporting Center, Post Office Box 1515, Lanham-Seabrook, Maryland 20703-1515. Telephone 301/429-5018.
   b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
   [40 CFR 68]

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

4. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
   [Rules 62-213.440(3) and 62-213.900, F.A.C.]

5. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southwest District Office, 13051 North Telecom Parkway, Temple Terrace, Florida 33637-0926. Telephone: 813/632-7600, Fax: 813/632-7665.

6. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, Air, Pesticides & Toxics Management Division, Air and EPCRA Enforcement Branch - Air Enforcement Section, 61 Forsyth Street, Atlanta, Georgia 30303. Telephone: 404/562-9155, Fax: 404/562-9164.

7. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
   [Rule 62-213.420(4), F.A.C.]

Section III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions units.

ARMS No.	Brief Description
001	One nominal 170 megawatt gas simple-cycle combustion turbine-electrical generator with evaporative inlet cooler.
002	One nominal 170 megawatt gas simple-cycle combustion turbine-electrical generator with evaporative inlet cooler.

These emissions units consist of two, dual-fuel, nominal 170 megawatt (MW) General Electric model PG7241FA combustion turbine-electrical generators with evaporative inlet coolers, and two 75-foot exhaust stacks. The units can operate in simple-cycle mode and intermittent duty mode. The units are equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. A continuous emissions monitoring system (CEMS) monitors NOx from the combustion turbines.

{Permitting note: These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C., Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT), and Air Construction Permit PSD-FL-284 (0270016-001-AC).}

Compliance Assurance Monitoring (CAM) *does not apply* to these emissions units because CEMS is being used to show compliance with NOx emissions limit.

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

General

A.1. BACT Determination. In accordance with Rule 62-212.400(12), 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); Rule 62-212.400(12), F.A.C.; and 0270016-001-AC, Specific Condition 7. in Facility Information Section]

Essential Potential to Emit (PTE) Parameters

A.2. Permitted Capacity. The nominal heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (001 and 002) 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 nominal heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correcting to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and 0270016-001-AC, Specific Condition 8.]

A.3. Methods of Operation -- Fuels. Only pipeline natural gas or a maximum of 0.05%, by weight, sulfur fuel oil No. 2, or superior grade of distillate fuel oil, shall be fired in these units.
{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.}
[Rules 62-210.200 (Definitions - Potential Emissions) and 62-213.410, F.A.C.; and 0270016-001-AC, Specific Condition 7.]

A.4. 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. During any consecutive 12-month period that includes an episode where natural gas availability is limited (e.g., gas supply is scheduled and flowing to the facility, but is subsequently interrupted and discontinued; gas supply is requested based on apparent availability, but is not able to be scheduled due to actual unavailability; and gas transportation is known to be restricted such that no request to schedule supplies would reasonably be fulfilled), the amount of back-up fuel (fuel oil) burned at the site (in BTU's) may exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) for that consecutive 12-month period. The permittee shall provide notification (telephonic or e-mail) of each episode within 2 business days to the Department's Southwest District Office until September 30, 2008. Thereafter, the permittee shall provide quarterly documentation of the episodes to the Department's Southwest District Office. The documentation shall include the dates of the episodes, the reasons provided by the supplier for limited natural gas availability, and the duration of each episode during that quarter.
[Rule 62-210.200, F.A.C. (BACT); and 0270016-001-AC, Specific Condition 14.]

A.5. Hours of Operation. The two stationary gas turbines shall operate no more than an average of 3,390 hours per unit during any calendar year. The two stationary gas turbines shall operate no more than an average of 1000 hours per unit on fuel oil during any calendar year. No single combustion turbine shall operate more than 5,000 hours in a single year.
[Rules 62-4.160(2), 62-210.200(PTE), and 62-212.400, F.A.C.; and 0270016-001-AC, Specific Condition 13.]

Control Technology

A.6. DLN Combustion. Dry Low NO_X (DLN-2.6) combustors shall be used on the stationary combustion turbines to control nitrogen oxides (NO_X) emissions while firing natural gas.
[Rules 62-4.070 and 62-212.400, F.A.C.; and 0270016-001-AC, Specific Condition 15.]

A.7. Water Injection. The water injection (WI) system shall be used when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions.
[Rules 62-4.070 and 62-212.400, F.A.C.; and 0270016-001-AC, Specific Condition 16.]

A.8. Performance Curves. 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.
[Rules 62-4.070 and 62-210.650 F.A.C.; and 0270016-001-AC, Specific Condition 17.]

Emission Limitations and Standards

{Permitting notes: Appendix P, Permit Summary Tables, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit. Unless otherwise specified, the averaging times for emissions standards are based on the specified averaging time of the applicable test method.}

A.9. Summary of Emissions Standards. 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.

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 by weight (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)

[Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.; and 0270016-001-AC, Specific Condition 18.]

A.10. Nitrogen Oxides (NO_X) Emissions.

a. 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 Specific Condition **A.20.** for a discussion of 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.]

b. 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 block 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.]

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.

[0270016-001-AC, Specific Condition 19.]

A.11. Carbon Monoxide (CO) Emissions. The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 42.5 lb/hr (at ISO conditions) while firing gas, and neither 20 ppmvd nor 71.4 lb/hr (at ISO conditions) while firing fuel oil. The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.; and 0270016-001-AC, Specific Condition 20.]

A.12. 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.
[Rule 62-212.400, F.A.C.; and 0270016-001-AC, Specific Condition 21.]

A.13. 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 feet) or by firing No. 2 or superior grade distillate fuel oil with a maximum of 0.05 percent sulfur, by weight, 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; Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.; and 0270016-001-AC, Specific Condition 22.]

A.14. 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.; and 0270016-001-AC, Specific Condition 23.]

A.15. 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.; and 0270016-001-AC, Specific Condition 24.]

Excess Emission

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

A.16. Excess Emissions Permitted. 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 the Department for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).
[Rules 62-210.700(1) and (2), F.A.C.; and 0270016-001-AC, Specific Condition 25.]

A.17. Excess Emissions Prohibited. 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.
[Rule 62-210.700(4), F.A.C.; and 0270016-001-AC, Specific Condition 26.]

A.18. Excess Emissions Report. If excess emissions occur due to malfunction, the owner or operator shall notify the Department's Southwest District Office within one 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 (See Appendix NA), periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Conditions No. **A.9.** and **A.10.**
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7; and 0270016-001-AC, Specific Condition 27.]

Test Methods and Procedures

{Permitting note: Appendix P, Permit Summary Tables, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.19. Compliance with the allowable emission limiting standards shall be determined *annually* by using the following reference methods as described in 40 CFR 60, Appendix A adopted by reference in Chapter 62-204.800, F.A.C. *Initial (I) performance tests* (for both fuels) were performed on each unit while firing natural gas as well as while firing fuel oil. *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 Departmental approval is received in writing.

a. EPA Reference Method 9 (30 minutes), "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).

b. EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).

c. 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 40 CFR 60 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).

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

In accordance with Rule 62-297.310(7), F.A.C., the Department may require the *initial tests to be repeated after a modification (and shakedown period not to exceed 100 days after restart)* of a combustion turbine. Within 60 days of replacing combustors and restarting a unit, the permittee shall conduct an EPA Method 10 test to determine compliance with the CO emissions standard for firing natural gas. NOx CEMS data collected during each of the CO test runs shall be averaged and reported in the test report. The results of this test may be used to satisfy the requirement for an annual CO emissions test.

[Rule 62-297.310, F.A.C.; and Permit Nos. 0270016-001-AC, Specific Condition 28 and PSD-FL-284 B (0270016-004-AC), Specific Conditions 29.]

A.20. 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 Rule 62-210.700, F.A.C. These excess emissions periods shall be reported as required in Specific Conditions **A.16.** and **A.17.**

All continuous emissions 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.
[Rules 62-4.070 and 62-210.700, F.A.C., 40 CFR 75 and 40 CFR 60.13; and 0270016-001-AC, Specific Condition 30.]

A.21. Compliance with the SO_2 and PM/PM_{10} emission limits. Notwithstanding 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 CFR 60.335 or 40 CFR 75 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).
[0270016-001-AC, Specific Condition 31.]

A.22. 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.
[0270016-001-AC, Specific Condition 32.]

A.23. 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.
[0270016-001-AC, Specific Condition 33.]

Monitoring of Operations

A.24. Continuous Monitoring System. The permittee shall 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 75 and 40 CFR 60.7; and 0270016-001-AC, Specific Condition 40.]

A.25. 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 Nos. **A.9.** and **A.10.**, shall be reported to the Department's Southwest District Office 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).
[0270016-001-AC, Specific Condition 41.]

A.26. 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. The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.
[0270016-001-AC, Specific Condition 42.]

A.27. 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 40 CFR 75. 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. [0270016-001-AC, Specific Condition 43.]

A.28. 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:

a. The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
b. 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 1 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
c. Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
d. 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).

[0270016-001-AC, Specific Condition 44.]

A.29. 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 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 60.334(h). [0270016-001-AC, Specific Condition 45.]

Training Requirements

A.30. 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 or facility determined best practices after approval by the Department. The permittee shall submit the facility determined best practices to the Department prior to implementing the practices. All operators of air pollution control devices shall be properly trained in plant specific equipment.
[Rule 62-4.070(3), F.A.C.; and 0270016-001-AC, Specific Condition 11.]

Recordkeeping and Reporting Requirements

A.31. Reports, Records and Notifications. For additional reporting, recordkeeping and notification requirements see Appendix CC (Common Conditions), Appendix GC (General Conditions), Appendix NA (NSPS Subpart A, General Provisions), Appendix TV-6 (Title V Conditions), Appendix NGG (NSPS Subpart GG Provisions for Gas Turbines), Appendix STR (Standard Testing Requirements) and Appendix CFMS (Custom Fuel Monitoring Schedule for Natural Gas).

Section IV. Acid Rain Part.

DeSoto County Energy Park

ORIS code: 55422

The emissions units listed below are regulated under Phase II of the Federal Acid Rain Program.

EU No.	Description
001	One nominal 170 megawatt gas simple-cycle combustion turbine-electrical generator with evaporative inlet cooler.
002	One nominal 170 megawatt gas simple-cycle combustion turbine-electrical generator with evaporative inlet cooler.

1. The Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these acid rain units must comply with the standard requirements and special provisions set forth in the following application: DEP Form No. 62-210.900(1)(a), version 07/01/95, Revised Phase II Acid Rain Permit (Part) Application, signed and dated by the Designated Representative on September 12, 2007.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are:

EU No.	EPA ID #	Year	2008	2009	2010	2011	2012
001	CT1	SO_2 allowances to be determined by U.S. EPA.	0	0	0	0	0
002	CT2	SO_2 allowances to be determined by U.S. EPA.	0	0	0	0	0

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

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

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

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

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

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

SECTION V. APPENDICES

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number

"001" identifies the specific permit project

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Florida Statutes (F.S.)

Example: [Section 403.161, F.S.]

Means: Chapter 403, Section 161 of the Florida Statutes

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

MISCELLANEOUS

ARMS: Air Resource Management System

LIST OF INSIGNIFICANT EMISSIONS UNITS AND ACTIVITIES

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities:

1. Operation of a CO_2 based fire protection system to be used in case of emergency fire in or near the combustion turbines.
2. Operation of an electric based fire protection system for the building. The unit also contains a small space heater.
3. Operation of a 13.5 mmBtu/hr indirect fired fuel gas heater to prevent the natural gas from freezing.
4. Storage and handling operations for lube, transformer, and fuel oil.
5. Miscellaneous maintenance and cleaning and painting of the building including the control room, maintenance shop, storage warehouse, offices and their contents.
6. Miscellaneous heaters.
7. Miscellaneous general-purpose internal combustion engines for routine facility maintenance and/or equipment malfunctions.
8. Surface coating operations using VOCs.
9. Water analysis tasks to ensure proper operation of the water injection system and the combustion turbine cooling processes.
10. Storm water retention basin maintenance.
11. One 1.5 million gallon distillate fuel oil storage tank

COMMON CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. 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 permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; 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 or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions - Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. This state provision cannot be used to vary any applicable NSPS requirements from 40 CFR 60. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions - Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. This state provision cannot be used to vary any applicable NSPS requirements from 40 CFR 60. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program (designee) in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department or its designee. This state provision cannot be used to vary any applicable NSPS requirements from 40 CFR 60. [Rule 62-210.700(6), F.A.C.]
6. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department or its designee.

   Such controls include the following:

   a. Tightly cover or close all VOC containers when they are not in use.
   b. Tightly cover all open tanks which contain VOCs when they are not in use.
   c. Maintain all pipes, valves, fittings, etc., which handle VOCs in good operating condition.
   d. Confine rags used with VOCs to tightly closed, fire-proof containers when not in use.
   e. Immediately confine and clean up VOC spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

   [Rule 62-296.320(1), F.A.C.]
7. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Particulate Emissions Limiting Standard. General Visible Emissions Standard: Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: No person shall cause, let, permit, suffer or allow the emission 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 emission.

   Reasonable precautions include the following:

   a. Paving and maintenance of roads, parking areas and yards.
   b. Application of water or other dust suppressants to control emission from such activities as demolition of buildings, grading roads, construction, and land clearing.
   c. Application of asphalt, water, or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
   d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.
   e. Landscaping or planting of vegetation.
   f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
   g. Confining abrasive blasting where possible.
   h. Enclosure or covering of conveyor systems.
   i. Posting and enforcing a speed limit for vehicles traveling on roadways on site.

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

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department or its designee upon request. [Rule 62-213.440(1)(b)2., F.A.C.]

11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

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

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160. F.A.C.

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

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment. practices. or operations regulated or required under this permit, and.
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

8. If. for any reason. the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit. the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance: and

   b. The period of noncompliance, including dates and times; or, if not corrected. the anticipated time the non-compliance is expected to continue. and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules. except where such use is prescribed by Sections 403.73 and 403.111, F.S. Such evidence

shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (Applicable);
    b. Determination of Prevention of Significant Deterioration (Applicable); and,
    c. Compliance with New Source Performance Standards (NSPS Subparts A and GG).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

       {Permitting note: The conditional exemption for asphalt concrete plants at Rule 62-210.300(3)(c)2.g., F.A.C., requires the retention of all records for five (5) years.}

    c. Records of monitoring information shall include:

       (1) The date, exact place, and time of sampling or measurements;
       (2) The person responsible for performing the sampling or measurements;
       (3) The dates analyses were performed;
       (4) The person responsible for performing the analyses;
       (5) The analytical techniques or methods used; and
       (6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

COMPLIANCE TESTING REQUIREMENTS

1. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
2. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]
3. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
4. Applicable Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C. [Rule 62-297.310(4), F.A.C.]
   a. *Required Sampling Time.*
      (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
         (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
   b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
   c. *Required Flow Rate Range.* For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling

which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sample volume will be obtained.

d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

Table 62-297.310-1 CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass. thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calibration liquid in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: Annually - When received; - When 5% change observed. 2. One Point: Semiannually 3. Check after each test series	Spirometer or calibrated wet test or dry gas test meter Comparison check	2% 5%

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

5. Determination of Process Variables: [Rule 62-297.310(5), F.A.C.]

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

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

6. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

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

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

c. *Sampling Ports.*

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

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

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

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

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

d. *Work Platforms.*

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

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

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

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

e. *Access to Work Platform.*

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

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

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

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

g. *Sampling Equipment Support.*

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

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

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

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

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

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

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

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

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

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

(a) Did not operate; or

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

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

(a) Visible emissions, if there is an applicable standard;

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

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

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

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

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to

paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

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

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

RECORDS AND REPORTS

8. Test Reports: [Rule 62-297.310(8), F.A.C.]

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

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

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

SAMPLING TESTING REQUIREMENTS

8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

ATTACHMENT DCEP-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT DCEP-EU1-IV3

ALTERNATIVE METHODS OF OPERATION
SIMPLE-CYCLE COMBUSTION TURBINES 1 AND 2

The simple-cycle combustion turbines 1 and 2 at the DCEP are permitted to fire pipeline natural gas and low-sulfur No. 2 distillate fuel oil. Distillate fuel oil is used as backup fuel. The maximum sulfur content of the fuel oil may not exceed 0.05 percent (by weight). The turbines are permitted to operate no more than an average of 3,390 hours per unit during any calendar year; i.e., both turbines are authorized to operate a total of 6,780 hours during any calendar year. The turbines are also permitted to operate no more than an average of 1,000 hours per unit on fuel oil during any calendar year. One single turbine is permitted to operate no more than 5,000 hours in a single year.