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BUREAU OF AIR REGULATION

VANDOLAH POWER PROJECT

TITLE V OPERATION PERMIT RENEWAL APPLICATION

Dept. of Environmental Protection

JUN 05 2007

Southwest District

Prepared for:

VANDOLAH POWER COMPANY L.L.C.
WAUCHULA, FLORIDA

Prepared by:

ECT

Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 060821-0100

May 2007

INTRODUCTION

Vandolah Power Company L.L.C. currently operates four natural gas-fired simple cycle combustion turbine-electrical generators (EU 001 through EU 004) at the Vandolah Power Project located in Wauchula, Hardee County, Florida. Operation of Vandolah Power Project is currently authorized by FINAL Title V Air Operation Permit No. 0490043-003-AV. FINAL Permit No. 0490043-003-AV was issued with an effective date of January 1, 2003, and expires on December 31, 2007.

Pursuant to Rule 62-213.420(1)(a)3. and Rule 62-4.090, Florida Administrative Code (F.A.C.), an application for renewal of a Title V operation permit must be submitted 180 days prior to the expiration date of the current Title V permit. Since FINAL Title V Permit No. 0490043-003-AV expires on December 31, 2007, the permit renewal application for Vandolah Power Project must be submitted no later than July 1, 2007. This application package, consisting of Florida Department of Environmental Protection's (FDEP's) Application for Air Permit—Long Form and all required supplemental facility and emission unit information, constitutes Vandolah Power Company's Title V permit renewal application for Vandolah Power Project and is submitted to satisfy the requirements of Section 62-213.400, F.A.C.

Vandolah Power Company L.L.C., is requesting changes to the current Title V permit which are identified in Attachment G.

Attachment A—Facility Location Map and Plot Plan
Attachment B—Process Flow Diagram
Attachment C—Precautions to Prevent Emissions of Unconfined Particulate Matter
Attachment D—List of Insignificant Activities
Attachment E—Identification of Applicable Requirements
Attachment F—Compliance Report and Plan
Attachment G—Requested Changes to Current Title V Air Operation Permit
Attachment H—Fuel Analysis or Specification
Attachment I—Detailed Description of Control Equipment
Attachment J—Procedures for Startup and Shutdown
Attachment K—Operation and Maintenance Plan
Attachment L—Combustion Turbine Design Information
Attachment M—Acid Rain Permit Application

Department of Environmental Protection

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Southwest District

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for any air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes 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/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

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To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Vandolah Power Company L.L.C.**
2. Site Name: **Vandolah Power Project**
3. Facility Identification Number: **0490043**
4. Facility Location...
   Street Address or Other Locator: **2394 Vandolah Road**
   City: **Wauchula** County: **Hardee** Zip Code: **33873**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Mr. Chris Coombs**
2. Application Contact Mailing Address...
   Organization/Firm: **Vandolah Power Company**
   Street Address: **2394 Vandolah Road**
   City: **Wauchula** State: **Florida** Zip Code: **33873**
3. Application Contact Telephone Numbers...
   Telephone: **(863) 773 - 2277** ext. **2228** Fax: **(863) 773 - 5908**
4. Application Contact Email Address: **chris.coombs@northernstargen.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 6/8/2007	3. PSD Number (if applicable):
2. Project Number(s): 0490043-005-AV	4. Siting Number (if applicable):

Purpose of Application

This application for air permit is 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

Emissions Unit ID 001, 002, 003, and 004 will be subject to the Clean Air Interstate Rule (CAIR) requirements when these requirements become effective.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator	N/A	N/A
002	One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator	N/A	N/A
003	One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator	N/A	N/A
004	One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator	N/A	N/A

Application Processing Fee

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

APPLICATION INFORMATION

N/A

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 Email Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility 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 requirements identified in this application to which the facility 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.* Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1.	Application Responsible Official Name: **Mr. Douglas A. Jensen**
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.
3.	Application Responsible Official Mailing Address... Organization/Firm: **Vandolah Power Company** Street Address: **2394 Vandolah Road** City: **Wauchula** State: **Florida** Zip Code: **33873**
4.	Application Responsible Official Telephone Numbers... Telephone: **(863) 773 - 2277** ext. **2222** Fax: **(863) 773 - 5908**
5.	Application Responsible Official Email Address: **doug.jensen@northernstargen.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.* Signature Date 6/4/07

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Thomas W. Davis**
   Registration Number: **36777**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Environmental Consulting & Technology, Inc.**
   Street Address: **3701 NW 98th Street**
   City: **Gainesville** State: **Florida** Zip Code: **32606**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 332 - 0444** ext. **11351** Fax: **(352) 332 - 6722**
4. Professional Engineer Email Address: **tdavis@ectinc.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.

Signature: [signature] Date: 5/30/07

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **407.85** North (km) **3044.5**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27° 31' 22"** Longitude (DD/MM/SS) **81° 55' 28"**	
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: **Mr. Chris Coombs**
2. Facility Contact Mailing Address... Organization/Firm: **Vandolah Power Company** Street Address: **2394 Vandolah Road** City: **Wauchula** State: **Florida** Zip Code: **33873**
3. Facility Contact Telephone Numbers: Telephone: **(863) 773 - 2277** ext. **2228** Fax: **(863) 773 - 5908**
4. Facility Contact Email Address: **chris.coombs@northernstargen.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 Email Address:

<u>**Facility Regulatory Classifications**</u>

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:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	**A**	**Y**
CO	**A**	**Y**
VOC	**SM**	**Y**
SO2	**A**	**Y**
PM	**SM**	**Y**
PM10	**SM**	**Y**

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	**A**	**Y**
CO	**A**	**Y**
VOC	**SM**	**Y**
SO2	**A**	**Y**
PM	**SM**	**Y**
PM10	**SM**	**Y**

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 No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap
NOX	**Y**		**N/A**	**1,008.4**	**OTHER**
CO	**Y**		**N/A**	**346.0**	**OTHER**
VOC	**Y**		**N/A**	**45.6**	**OTHER**
SO2	**Y**		**N/A**	**221.2**	**OTHER**
PM/PM10	**Y**		**N/A**	**82.0**	**OTHER**

7. Facility-Wide or Multi-Unit Emissions Cap Comment:
Facility-Wide emissions cap is based on each CT operating up to an average of 3,390 hours per year, of which, 1,000 hours per year on distillate fuel oil. Potential emissions for each emissions unit (CT) are based on operating up to 5,000 hours per year, of which, 1,000 hours per year on distillate fuel oil.

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: **Attachment A** ☐ 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: **Attachment B** ☐ 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: **Attachment C** ☐ Previously Submitted, Date:________

Additional Requirements for Air Construction Permit Applications **N/A**

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 (Rule 62-210.300(3), F.A.C.): ☐ 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

Additional Requirements for FESOP Applications N/A

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ 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: **Attachment D** ☐ 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: **Attachment E** ☐ 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: **Attachment F** 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 On site 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: **Attachment G** ☐ Not Applicable	

Additional Requirements Comment

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:
One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**N/A**	**4/2002**	**49**	☒ Yes ☐ No

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

10. Generator Nameplate Rating: **170 (nominal)** MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NOx Burners – Natural Gas Firing** **Water Injection – Distillate Fuel Oil Firing**
2. Control Device or Method Code(s): **025, 028**

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:	
3. Maximum Heat Input Rate: **1,969.0** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **5,000** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input of 1,969.0 MMBtu/hr based on higher heating value (HHV), distillate oil firing at 100% load and 32°F ambient temperature.** **5,000 hr/yr maximum per turbine. 3,390 hr/yr average per turbine.**	

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: **GT101**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: 75 feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: **8.6 % (vol.)**

11. Maximum Dry Standard Flow Rate: **798,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **408.75** North (km): **3044.5**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on natural gas-firing at 100% load and 59°F ambient temperature.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 2_

1. Segment Description (Process/Fuel Type): **Pipeline Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.796**	5. Maximum Annual Rate: **8,666.7**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **930**
10. Segment Comment: **Maximum Annual rate based on 5,000 hours per year.** **930 MMBtu/MMcf based on lower heating value (LHV).** **Maximum hourly rate = (1,670.0 MMBtu/hr) / (930 MMBtu/MMcf) = 1.796 MMcf/hr (Based on 32°F)** **Maximum annual rate = ([1,612.0 MMBtu/hr] / [930 MMBtu/MMcf]) x (5,000 hr/yr) = 8,666.7 MMcf/yr (Based on 59°F and 5,000 hr/yr per turbine)**		

Segment Description and Rate: Segment 2_ of 2_

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons**	
4. Maximum Hourly Rate: **14.4**	5. Maximum Annual Rate: **14,000 (average)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **129**
10. Segment Comment: **Maximum hourly rate = (1,858 MMBtu/hr) / (129 MMBtu/Kgal) = 14.4 Kgal/hr (Based on 32°F)** **Maximum annual rate = ([1,806 MMBtu/hr] / [129 MMBtu/Kgal]) x (1,000 hr/yr) = 14,000 Kgal/yr (Average per turbine, based on 59°F at 4,000 hr/yr total for all four turbines)** **129 MMBtu/Kgal based on lower heating value (LHV).**		

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
NOX	**025, 028**		**EL**
CO			**EL**
VOC			**EL**
SO2			**EL**
PM			**EL**
PM10			**EL**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **351** lb/hour **303.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 303.7 tons per year based on 4,000 hours per year of natural gas-firing at 64.1 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 351 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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% O_2**	4. Equivalent Allowable Emissions: **64.1** lb/hour **128.2** tons/year
5. Method of Compliance: **24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 64.1 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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% O_2**	4. Equivalent Allowable Emissions: **351** lb/hour **175.5** tons/year
5. Method of Compliance: **3-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 351 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4** lb/hour **120.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 71.4 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 120.7 tons per year based on 4,000 hours per year of natural gas-firing at 42.5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 71.4 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

<u>**Allowable Emissions**</u> 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**	4. Equivalent Allowable Emissions: **42.5** lb/hour **85.0** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 42.5 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

<u>**Allowable Emissions**</u> 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**	4. Equivalent Allowable Emissions: **71.4** lb/hour **35.7** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 71.4 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

<u>**Allowable Emissions**</u> 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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **13.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 16.2 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 13.7 tons per year based on 4,000 hours per year of natural gas-firing at 2.8 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 16.2 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **2.8** lb/hour **5.6** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 2.8 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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 @ 15% O_2**	4. Equivalent Allowable Emissions: **16.2** lb/hour **8.1** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 16.2 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **98.7** lb/hour **59.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 59.4 tons per year based on 4,000 hours per year of natural gas-firing at 5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 98.7 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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 grain per 100 standard cubic feet**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Exclusive use of pipeline natural gas and natural gas supplier data (A.16 and A.25)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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: **0.05 % sulfur by weight**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Fuel analysis for sulfur content. Exclusive use of No. 2 or superior grade fuel oil and fuel oil supplier data.**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **28.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 17 lb/hr based on distillate fuel oil-firing. Potential annual emission rate of 28.5 tons per year based on 4,000 hours per year of natural gas-firing at 10 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 17 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1_ of 1_

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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):	

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 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: **Rule 62-212.400, F.A.C.**	

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: **99** % Maximum Period of Excess Opacity Allowed: **See comments** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions can exceed 10% opacity during periods of startup, shutdown and malfunction provided best operational practices are used to minimize emissions and excess emission can not exceed 2 hours in any 24-hour period. Rule 62-210.700(1), F.A.C.**	

H. CONTINUOUS MONITOR INFORMATION

Complete 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: **Spectrum** Model Number: **42C**	Serial Number: **42-CHL-69808-364**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment: **Rule 40 CFR Part 75**	

Continuous Monitoring System: Continuous Monitor 2__ of 2_

1. Parameter Code: **O2**	2. Pollutant(s): **N/A**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **3117**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: **Attachment B** ☐ 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: **Attachment H** ☐ 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: **Attachment I** ☐ 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: **Attachment J** ☐ 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: **Attachment K** ☐ Previously Submitted, Date ________
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ________________
   Test Date(s)/Pollutant(s) Tested: ________________

   ☒ Previously Submitted, Date: **07/21/2006**
   Test Date(s)/Pollutant(s) Tested: **NOx, CO, and VE**

   ☐ 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

Additional Requirements for Air Construction Permit Applications N/A

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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: **Attachment E**	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: __________ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: __________ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: __________ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☒ Acid Rain Part (Form No. 62-210.900(1)(a)) ☒ Attached, Document ID: Attachment M ☐ Previously Submitted, Date:_________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:_________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:_________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:_________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:_________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:_________ ☐ Not Applicable	

Additional Requirements Comment

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:
One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator

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

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **N/A**	6. Initial Startup Date: **4/2002**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? ☒ Yes ☐ No

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

10. Generator Nameplate Rating: **170 (nominal)** MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NOx Burners – Natural Gas Firing** **Water Injection – Distillate Fuel Oil Firing**
2. Control Device or Method Code(s): **025, 028**

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:		
3. Maximum Heat Input Rate: **1,969.0** million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week 5,000 hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input of 1,969.0 MMBtu/hr based on higher heating value (HHV), distillate oil firing at 100% load and 32°F ambient temperature.** **5,000 hr/yr maximum per turbine. 3,390 hr/yr average per turbine.**		

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: **GT201**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: **8.6 % (vol.)**

11. Maximum Dry Standard Flow Rate: **798,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **408.75** North (km): **3044.5**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on natural gas-firing at 100% load and 59°F ambient temperature.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 2_

1. Segment Description (Process/Fuel Type): **Pipeline Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.796**	5. Maximum Annual Rate: **8,666.7**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **930**

10. Segment Comment:
Maximum Annual rate based on 5,000 hours per year.
930 MMBtu/MMcf based on lower heating value (LHV).
Maximum hourly rate = (1,670.0 MMBtu/hr) / (930 MMBtu/MMcf) = 1.796 MMcf/hr (Based on 32°F)
Maximum annual rate = ([1,612.0 MMBtu/hr] / [930 MMBtu/MMcf]) x (5,000 hr/yr) = 8,666.7 MMcf/yr (Based on 59°F and 5,000 hr/yr per turbine)

Segment Description and Rate: Segment 2_ of 2_

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons**	
4. Maximum Hourly Rate: **14.4**	5. Maximum Annual Rate: **14,000 (average)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **129**

10. Segment Comment:
Maximum hourly rate = (1,858.0 MMBtu/hr) / (129 MMBtu/Kgal) = 14.4 Kgal/hr (Based on 32°F)
Maximum annual rate = ([1,806 MMBtu/hr] / [129 MMBtu/Kgal]) x (1,000 hr/yr) = 14,000 Kgal/yr (Average per turbine, based on 59°F at 4,000 hr/yr total for all four turbines)
129 MMBtu/Kgal based on lower heating value (LHV).

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
NOX	**025, 028**		**EL**
CO			**EL**
VOC			**EL**
SO2			**EL**
PM			**EL**
PM10			**EL**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **351** lb/hour **303.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 303.7 tons per year based on 4,000 hours per year of natural gas-firing at 64.1 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 351 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

<u>**Allowable Emissions**</u> 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% O_2**	4. Equivalent Allowable Emissions: **64.1** lb/hour **128.2** tons/year
5. Method of Compliance: **24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 64.1 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

<u>**Allowable Emissions**</u> 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% O_2**	4. Equivalent Allowable Emissions: **351** lb/hour **175.5** tons/year
5. Method of Compliance: **3-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 351 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

<u>**Allowable Emissions**</u> 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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4** lb/hour **120.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 71.4 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 120.7 tons per year based on 4,000 hours per year of natural gas-firing at 42.5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 71.4 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year, i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **42.5** lb/hour **85.0** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 42.5 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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**	4. Equivalent Allowable Emissions: **71.4** lb/hour **35.7** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 71.4 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **13.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 16.2 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 13.7 tons per year based on 4,000 hours per year of natural gas-firing at 2.8 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 16.2 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **2.8** lb/hour **5.6** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 2.8 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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 @ 15% O_2**	4. Equivalent Allowable Emissions: **16.2** lb/hour **8.1** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 16.2 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **98.7** lb/hour **59.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 59.4 tons per year based on 4,000 hours per year of natural gas-firing at 5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 98.7 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year, i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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 grain per 100 standard cubic feet**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Exclusive use of pipeline natural gas and natural gas supplier data (A.16 and A.25)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing,** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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: **0.05 % sulfur by weight**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Fuel analysis for sulfur content. Exclusive use of No. 2 or superior grade fuel oil and fuel oil supplier data.**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing,** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **28.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 17 lb/hr based on distillate fuel oil-firing. Potential annual emission rate of 28.5 tons per year based on 4,000 hours per year of natural gas-firing at 10 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 17 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1_ of 1__

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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):	

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 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**	
6. Visible Emissions Comment: **Rule 62-212.400, F.A.C.**	

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: **99 %** Maximum Period of Excess Opacity Allowed: **See comments** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions can exceed 10% opacity during periods of startup, shutdown and malfunction provided best operational practices are used to minimize emissions and excess emission can not exceed 2 hours in any 24-hour period. Rule 62-210.700(1), F.A.C.**	

H. CONTINUOUS MONITOR INFORMATION

Complete 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: **Spectrum** Model Number: **42C**	Serial Number: **42-CHL-69811-364**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment: **Rule 40 CFR Part 75**	

Continuous Monitoring System: Continuous Monitor 2_ of 2_

1. Parameter Code: **O2**	2. Pollutant(s): **N/A**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **3118**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: **Attachment B** ☐ 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: **Attachment H** ☐ 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: **Attachment I** ☐ 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: **Attachment J** ☐ 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: **Attachment K** ☐ Previously Submitted, Date ________ ☐ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ________________ Test Date(s)/Pollutant(s) Tested: ________________ ☒ Previously Submitted, Date: **07/21/2006** Test Date(s)/Pollutant(s) Tested: **NOx, CO, and VE** ☐ 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

Additional Requirements for Air Construction Permit Applications N/A

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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: **Attachment E**

2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: __________ ☒ Not Applicable

3. Alternative Methods of Operation
   ☐ Attached, Document ID: __________ ☒ Not Applicable

4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: __________ ☒ Not Applicable

5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:_
   ☒ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☒ Attached, Document ID: Attachment M ☐ Previously Submitted, Date:_________
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:_________
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:_________
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:_________
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:_________
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:_________
   ☐ Not Applicable

Additional Requirements Comment

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:
One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator

3. Emissions Unit Identification Number: **003**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**N/A**	**4/2002**	**49**	☒ Yes ☐ No

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

10. Generator Nameplate Rating: **170 (nominal)** MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NOx Burners – Natural Gas Firing** **Water Injection – Distillate Fuel Oil Firing**
2. Control Device or Method Code(s): **025, 028**

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:	
3. Maximum Heat Input Rate: **1,969.0** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **5,000** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input of 1,969.0 MMBtu/hr based on higher heating value (HHV), distillate oil firing at 100% load and 32°F ambient temperature.** **5,000 hr/yr maximum per turbine. 3,390 hr/yr average per turbine.**	

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: **GT301**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: **8.6 % (vol.)**

11. Maximum Dry Standard Flow Rate: **798,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **408.75** North (km): **3044.5**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on natural gas-firing at 100% load and 59°F ambient temperature.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 2_

1. Segment Description (Process/Fuel Type): **Pipeline Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.796**	5. Maximum Annual Rate: **8,666.7**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **930**
10. Segment Comment: **Maximum Annual rate based on 5,000 hours per year. 930 MMBtu/MMcf based on lower heating value (LHV). Maximum hourly rate = (1,670.0 MMBtu/hr) / (930 MMBtu/MMcf) = 1.796 MMcf/hr (Based on 32°F) Maximum annual rate = ([1,612.0 MMBtu/hr] / [930 MMBtu/MMcf]) x (5,000 hr/yr) = 8,666.7 MMcf/yr**		

Segment Description and Rate: Segment 2_ of 2_

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons**	
4. Maximum Hourly Rate: **14.4**	5. Maximum Annual Rate: **14,000 (average)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **129**
10. Segment Comment: **Maximum hourly rate = (1,858.0 MMBtu/hr) / (129 MMBtu/Kgal) = 14.4 Kgal/hr (Based on 32°F) Maximum annual rate = ([1,806 MMBtu/hr] / [129 MMBtu/Kgal]) x (1,000 hr/yr) = 14,000 Kgal/yr (Average per turbine, based on 59°F at 4,000 hr/yr total for all four turbines) 129 MMBtu/Kgal based on lower heating value (LHV).**		

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
NOX	**025, 028**		**EL**
CO			**EL**
VOC			**EL**
SO2			**EL**
PM			**EL**
PM10			**EL**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **351** lb/hour **303.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 303.7 tons per year based on 4,000 hours per year of natural gas-firing at 64.1 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 351 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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% O_2**	4. Equivalent Allowable Emissions: **64.1** lb/hour **128.2** tons/year
5. Method of Compliance: **24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 64.1 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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% O_2**	4. Equivalent Allowable Emissions: **351** lb/hour **175.5** tons/year
5. Method of Compliance: **3-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 351 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4** lb/hour **120.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 71.4 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 120.7 tons per year based on 4,000 hours per year of natural gas-firing at 42.5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 71.4 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **42.5** lb/hour **85.0** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 42.5 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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**	4. Equivalent Allowable Emissions: **71.4** lb/hour **35.7** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 71.4 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **13.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 16.2 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 13.7 tons per year based on 4,000 hours per year of natural gas-firing at 2.8 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 16.2 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **2.8** lb/hour **5.6** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 2.8 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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 @ 15% O_2**	4. Equivalent Allowable Emissions: **16.2** lb/hour **8.1** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 16.2 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **98.7** lb/hour **59.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 59.4 tons per year based on 4,000 hours per year of natural gas-firing at 5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 98.7 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year, i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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 grain per 100 standard cubic feet**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Exclusive use of pipeline natural gas and natural gas supplier data (A.16 and A.25)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing,** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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: **0.05 % sulfur by weight**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Fuel analysis for sulfur content. Exclusive use of No. 2 or superior grade fuel oil and fuel oil supplier data.**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing,** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 17 lb/hour **28.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 17 lb/hr based on distillate fuel oil-firing. Potential annual emission rate of 28.5 tons per year based on 4,000 hours per year of natural gas-firing at 10 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 17 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1_ of 1_

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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):	

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 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**	
7. Visible Emissions Comment: **Rule 62-212.400, F.A.C.**	

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: **99** % Maximum Period of Excess Opacity Allowed: **See comments** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions can exceed 10% opacity during periods of startup, shutdown and malfunction provided best operational practices are used to minimize emissions and excess emission can not exceed 2 hours in any 24-hour period. Rule 62-210.700(1), F.A.C.**	

H. CONTINUOUS MONITOR INFORMATION

Complete 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: **Spectrum** Model Number: **42C**	Serial Number: **42-CHL-69810-364**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment: **Rule 40 CFR Part 75**	

Continuous Monitoring System: Continuous Monitor 2_ of 2_

1. Parameter Code: **O2**	2. Pollutant(s): **N/A**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **3119**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: **Attachment B** ☐ 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: **Attachment H** ☐ 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: **Attachment I** ☐ 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: **Attachment J** ☐ 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: **Attachment K** ☐ Previously Submitted, Date ________
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____________
   Test Date(s)/Pollutant(s) Tested: ________________________________

   ☒ Previously Submitted, Date: **07/21/2006**
   Test Date(s)/Pollutant(s) Tested: **NOx, CO, and VE**

   ☐ 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

Additional Requirements for Air Construction Permit Applications N/A

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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: Attachment E	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ______ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ______ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ______ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☒ Acid Rain Part (Form No. 62-210.900(1)(a)) ☒ Attached, Document ID: Attachment M ☐ Previously Submitted, Date:______ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______ ☐ Not Applicable	

Additional Requirements Comment

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:
One nominal 170 megawatt dual fuel gas simple cycle combustion turbine-electrical generator

3. Emissions Unit Identification Number: **004**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	N/A	5/2002	49	☒ Yes ☐ No

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

10. Generator Nameplate Rating: **170 (nominal)** MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NOx Burners – Natural Gas Firing** **Water Injection – Distillate Fuel Oil Firing**	
2. Control Device or Method Code(s): **025, 028**	

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:	
3. Maximum Heat Input Rate: **1,969.0** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **5,000** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input of 1,969.0 MMBtu/hr based on higher heating value (HHV), distillate oil firing at 100% load and 32°F ambient temperature.** **5,000 hr/yr maximum per turbine. 3,390 hr/yr average per turbine.**	

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: **GT401**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: **8.6 % (vol.)**

11. Maximum Dry Standard Flow Rate: **798,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **408.75** North (km): **3044.5**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on natural gas-firing at 100% load and 59°F ambient temperature.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 2_

1. Segment Description (Process/Fuel Type): **Pipeline Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.796**	5. Maximum Annual Rate: **8,666.7**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **930**

10. Segment Comment:

Maximum Annual rate based on 5,000 hours per year.
930 MMBtu/MMcf based on lower heating value (LHV).
Maximum hourly rate = (1,670.0 MMBtu/hr) / (930 MMBtu/MMcf) = 1.796 MMcf/hr (Based on 32°F)
Maximum annual rate = ([1,612.0 MMBtu/hr] / [930 MMBtu/MMcf]) x (5,000 hr/yr) = 8,666.7 MMcf/yr (Based on 59°F and 5,000 hr/yr per turbine)

Segment Description and Rate: Segment 2_ of 2_

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons**	
4. Maximum Hourly Rate: **14.4**	5. Maximum Annual Rate: **14,000 (average)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **129**

10. Segment Comment:

Maximum hourly rate = (1,858.0 MMBtu/hr) / (129 MMBtu/Kgal) = 14.4 Kgal/hr (Based on 32°F)
Maximum annual rate = ([1,806 MMBtu/hr] / [129 MMBtu/Kgal]) x (1,000 hr/yr) = 14,000 Kgal/yr (Average per turbine, based on 59°F at 4,000 hr/yr total for all four turbines)
129 MMBtu/Kgal based on lower heating value (LHV).

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
NOX	**025, 028**		**EL**
CO			**EL**
VOC			**EL**
SO2			**EL**
PM			**EL**
PM10			**EL**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **351** lb/hour **303.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 303.7 tons per year based on 4,000 hours per year of natural gas-firing at 64.1 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 351 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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% O_2**	4. Equivalent Allowable Emissions: **64.1** lb/hour **128.2** tons/year
5. Method of Compliance: **24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 64.1 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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% O_2**	4. Equivalent Allowable Emissions: **351** lb/hour **175.5** tons/year
5. Method of Compliance: **3-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 351 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4** lb/hour **120.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 71.4 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 120.7 tons per year based on 4,000 hours per year of natural gas-firing at 42.5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 71.4 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **42.5** lb/hour **85.0** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 42.5 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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**	4. Equivalent Allowable Emissions: **71.4** lb/hour **35.7** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 71.4 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **13.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 16.2 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 13.7 tons per year based on 4,000 hours per year of natural gas-firing at 2.8 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 16.2 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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**	4. Equivalent Allowable Emissions: **2.8** lb/hour **5.6** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, 2.8 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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 @ 15% O_2**	4. Equivalent Allowable Emissions: **16.2** lb/hour **8.1** tons/year
5. Method of Compliance: **Compliance with CO emission limit (A.27)**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, 16.2 lb/hr based on ISO conditions** **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **98.7** lb/hour **59.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 351 lb/hr based on distillate fuel oil-firing at ISO conditions. Potential annual emission rate of 59.4 tons per year based on 4,000 hours per year of natural gas-firing at 5 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 98.7 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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 grain per 100 standard cubic feet**	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: **Exclusive use of pipeline natural gas and natural gas supplier data (A.16 and A.25)**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural Gas-Firing, Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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: **0.05 % sulfur by weight**	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: **Fuel analysis for sulfur content. Exclusive use of No. 2 or superior grade fuel oil and fuel oil supplier data.**	
6. Allowable Emissions Comment (Description of Operating Method): **Distillate Fuel Oil-Firing, Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 17 lb/hour **28.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:

Potential hourly emission rate of 17 lb/hr based on distillate fuel oil-firing. Potential annual emission rate of 28.5 tons per year based on 4,000 hours per year of natural gas-firing at 10 lb/hr and 1,000 hours per year of distillate fuel oil-firing at 17 lb/hr. (Based on ISO conditions.)

Note: Each CT is allowed to operate up to 5,000 hours per year, which includes a maximum of 1,000 hours per year while firing distillate fuel oil. All four CTs combined are allowed to operate a total of 13,560 hours per calendar year (i.e. an average of 3,390 hours per year per CT with 1,000 hours per year while firing distillate fuel oil).

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1**_ of **1**_

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Air Permit No. PSD-FL-275(0490043-001-AC); 62-212.400(BACT); F.A.C.**	

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):	

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 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**	
8. Visible Emissions Comment: **Rule 62-212.400, F.A.C.**	

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: **99** % Maximum Period of Excess Opacity Allowed: **See comments** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions can exceed 10% opacity during periods of startup, shutdown and malfunction provided best operational practices are used to minimize emissions and excess emission can not exceed 2 hours in any 24-hour period. Rule 62-210.700(1), F.A.C.**	

H. CONTINUOUS MONITOR INFORMATION

Complete 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: **Spectrum** Model Number: **42C**	Serial Number: **42-CHL-71442-364**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment: **Rule 40 CFR Part 75**	

Continuous Monitoring System: Continuous Monitor **2**_ of **2**_

1. Parameter Code: **O2**	2. Pollutant(s): **N/A**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **3115**
5. Installation Date: **April 8, 2002**	6. Performance Specification Test Date: **April 8, 2002**
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: **Attachment B** ☐ 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: **Attachment H** ☐ 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: **Attachment I** ☐ 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: **Attachment J** ☐ 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: **Attachment K** ☐ Previously Submitted, Date ________
☐ Not Applicable

6. Compliance Demonstration Reports/Records
☐ Attached, Document ID: ____________
Test Date(s)/Pollutant(s) Tested: ____________

☒ Previously Submitted, Date: **07/21/2006**
Test Date(s)/Pollutant(s) Tested: **NO_x, CO, and VE**

☐ 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

Additional Requirements for Air Construction Permit Applications N/A

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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: **Attachment E**	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ________ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ________ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ________ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☒ Acid Rain Part (Form No. 62-210.900(1)(a)) ☒ Attached, Document ID: Attachment M ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT A

FACILITY LOCATION MAP AND PLOT PLAN

M:/ACAD/060821/Vicinity.mxd

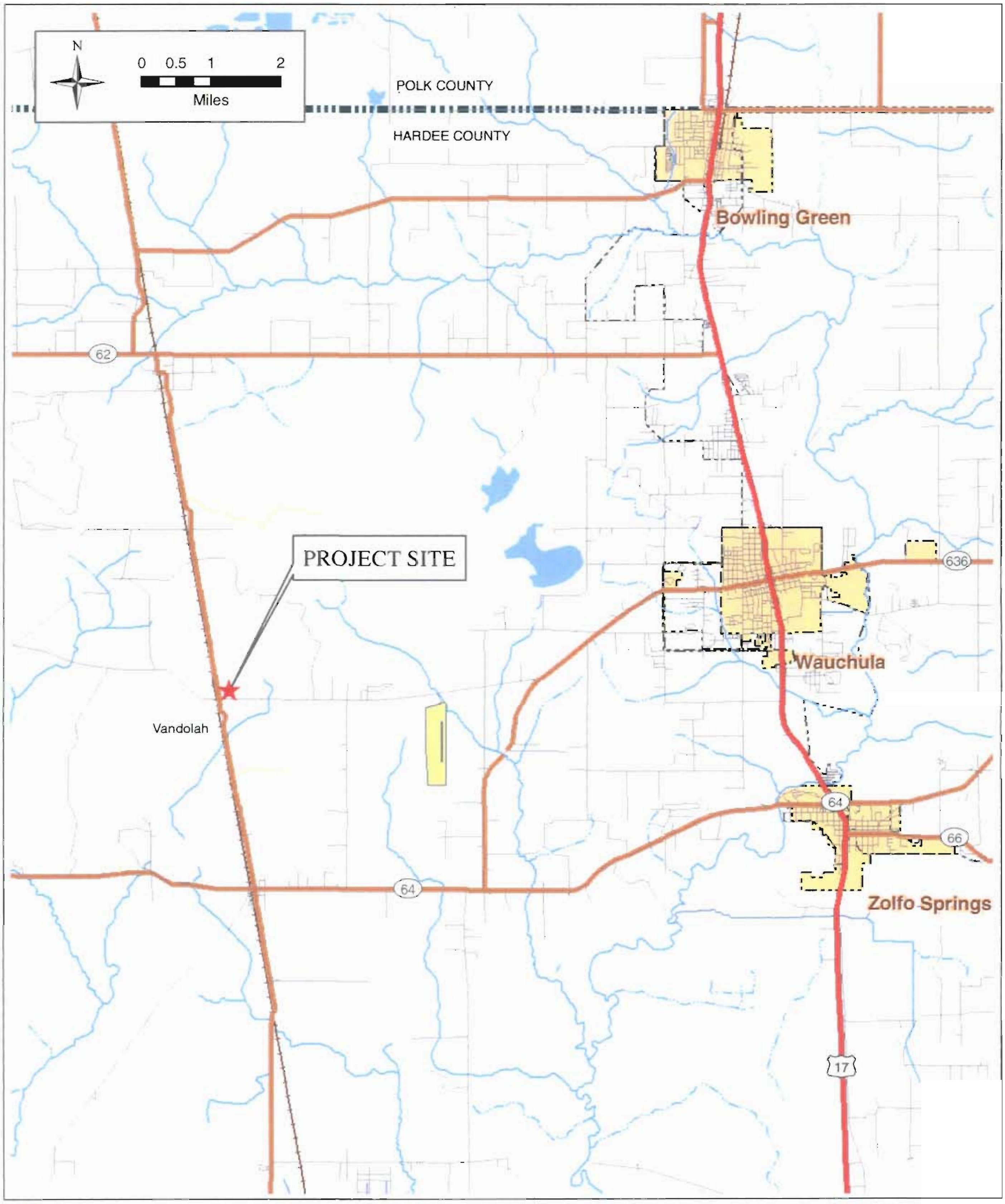

FIGURE A-1.
VICINITY MAP
VANDOLAH POWER PROJECT

Sources: ESRI Street Map 2006; ECT, 2006.

ECT
Environmental Consulting & Technology, Inc.

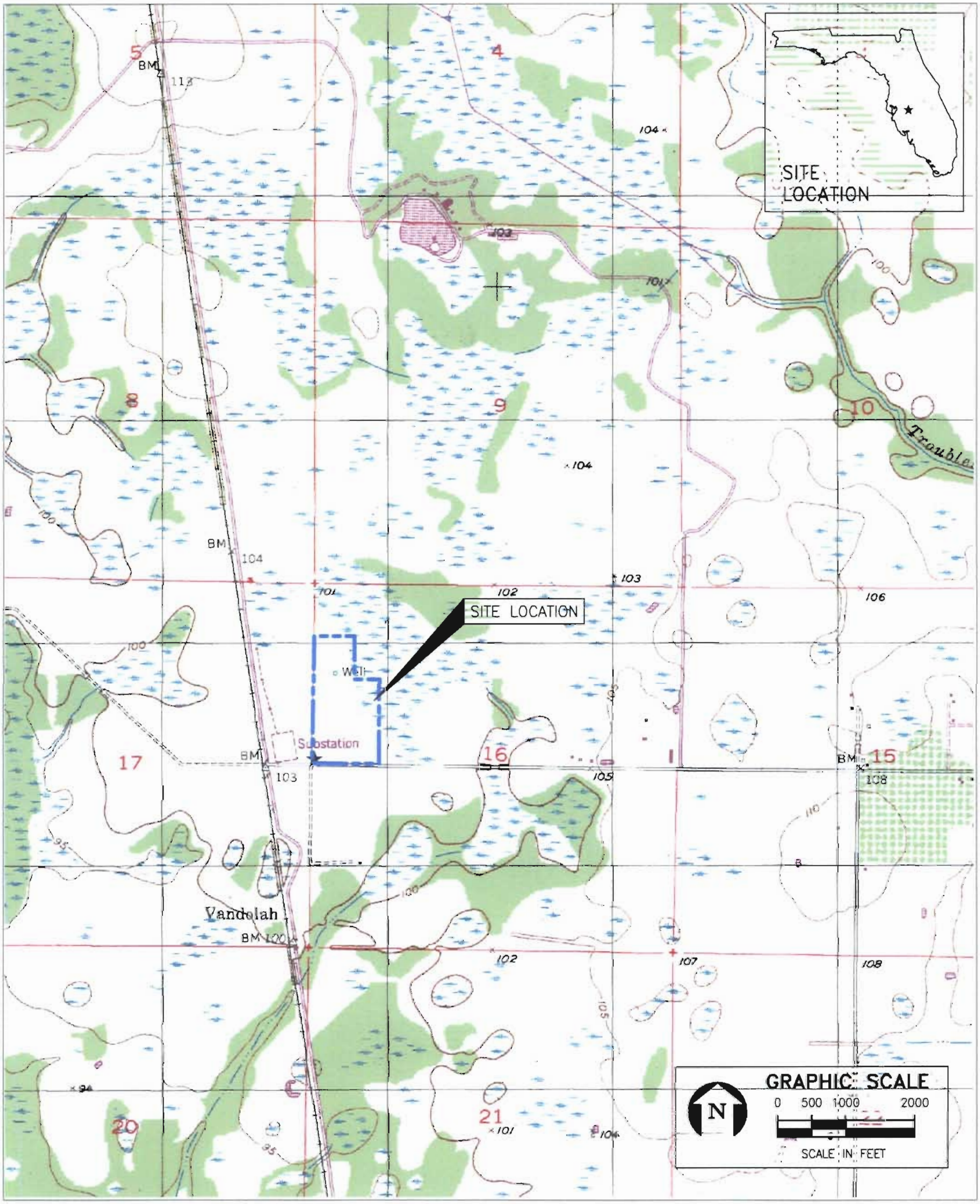

FIGURE A-2.
SITE LOCATION MAP
VANDOLAH POWER PROJECT

Source: USGS Quad: Ft. Green, FL, 1987; ECT, 2006.

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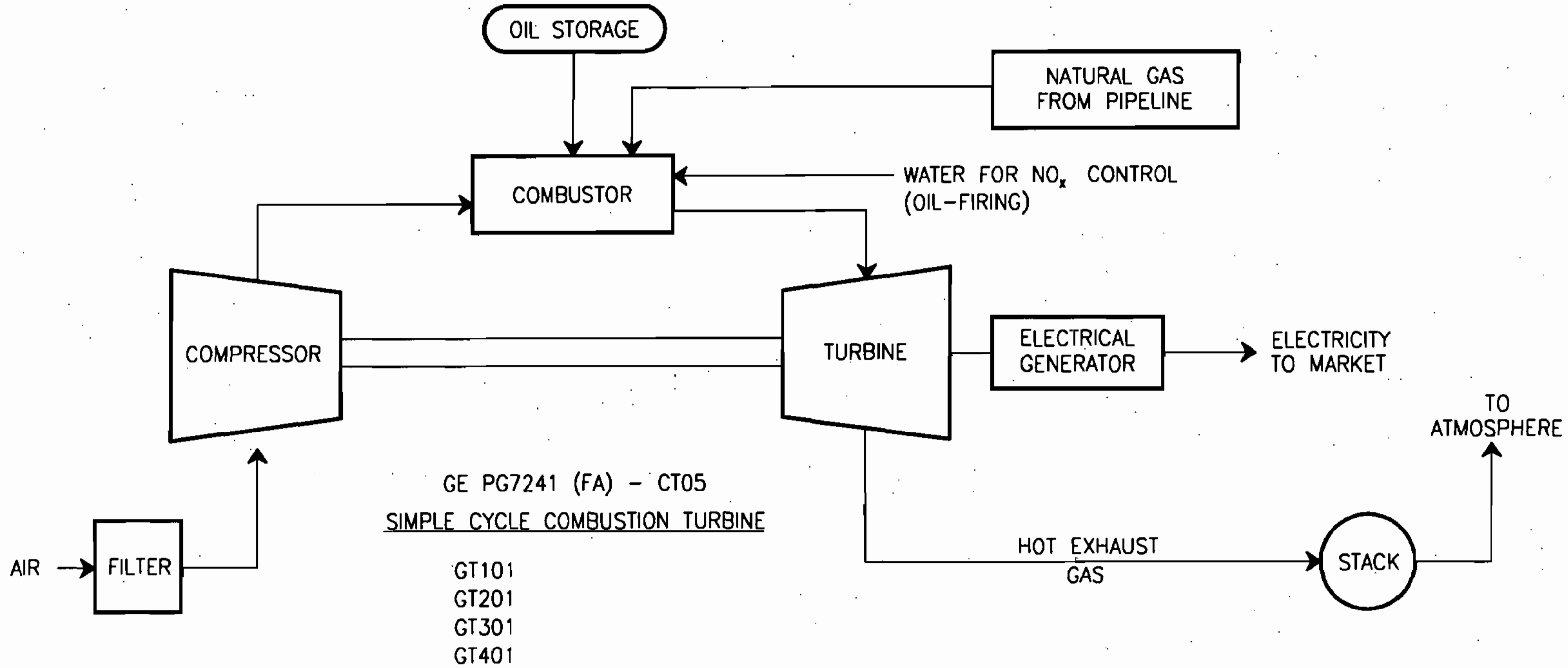
ATTACHMENT B

PROCESS FLOW DIAGRAM



ATTACHMENT B.

SIMPLE CYCLE COMBUSTION TURBINE: PROCESS FLOW DIAGRAM

Source: ECT, 2007.

ECT
Environmental Consulting & Technology, Inc.

ATTACHMENT C

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT C

VANDOLAH POWER COMPANY, LLC
VANDOLAH POWER PROJECT

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter (PM) emissions that may result from operations include:

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

The following techniques will be used to prevent unconfined PM emissions on an as needed basis:

- Chemical or water application to:
  - Unpaved roads
  - Unpaved yard areas
- Paving and maintenance of roads, parking areas and yards.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary

ATTACHMENT D

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT D

VANDOLAH POWER COMPANY, LLC
VANDOLAH POWER PROJECT

LIST OF INSIGNIFICANT ACTIVITIES

The following list of insignificant activities is identical to Appendix I-1, List of Insignificant Units and/or Activities, under current Final Permit No. 0490043-003-AV except for the addition of the two 2.8-million-gallon fuel oil storage tanks currently identified as EU 005 and 006. These two emissions units are no longer subject to 40 CFR Part 60 Subpart Kb effective October 15, 2003, and therefore, Vandolah Power Project is requesting these emissions units be considered insignificant.

1. Operation of a CO_2 based fire protection system to be used in case of emergency fire in or near the combustion turbines, warehouse buildings, and fuel oil tanks.

2. Operation of a Clark Diesel based fire protection system for the operations/maintenance building. The unit is rated at 265 BHP.

3. Operation of a 17 MMBtu/hr indirect fired fuel gas heater to ensure the natural gas during operations remains above the dew point.

4. Storage operations for the fuel oil storage locations described in Attachment VP-FI-C5 including the fuel oil truck unloading area.

5. Miscellaneous maintenance and cleaning and painting of the operations/ maintenance 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; both >5 percent and 5 percent VOC

9. Demin water analyses operations to ensure proper operation of the water injection system.

10. Stormwater retention basin and/or percolation pond maintenance (if required).

11. Various maintenance shop equipment including: drill press, bench grinder, sandblasting equipment, air compressor, and a pipe threader.

12. Raw water analyses in the combustion turbine glycol cooling loop for corrosion control and cooling.

13. Evaporative inlets for turbine cooling.

14. Operation of a CO_2-based generator purge system to be used when removing the generators from service, or in the event of an emergency purge of the normally H_2-filled generator.

15. Operation of a H_2-filled generator, which will be purged for maintenance or in the case of an emergency.

16. Operation of a foam suppression fire protection system for the fuel oil storage tanks.

17. Two 2.8 million gallon fuel oil storage tanks.

18. Four 375 kw each diesel-fired emergency generators.

19. Two 1,400 gallon diesel fuel aboveground storage tanks (AST).

20. One 1,000 gallon gasoline AST.

21. Three FM 200 fire protection systems.

22. Four 3,600 gallon waterwash drain tanks.

23. Four 500 gallon diesel fuel/water surge tanks.

24. One 500 gallon diesel fuel tank for general use.

ATTACHMENT E

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Table E-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources				
40 CFR Part 60 - Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP,QQQ, RRR, SSS, TTT, UUU, VVV, WWW, AAAA, BBBB, CCCC, DDDD, EEEE, FFFF, HHHH and KKKK		X		None of the listed NSPS' contain requirements that are applicable to Vandolah Power Project. **Note**: The two existing 2.8 million gallon fuel oil storage tanks are exempt from 40 CFR Part 60 Subpart Kb, effective October 15, 2003 since vapor pressure of stored liquid is less than 3.5 kPa.
40 CFR Part 60 Subpart A - General Provisions				
Notification and Recordkeeping	60.7(a)		EU 001 - 004	Notification requirements.
	60.7(b) - (h)		EU 001 - 004	General recordkeeping and reporting requirements.
Performance Tests	60.8		EU 001 - 004	Conduct initial performance tests as required by EPA.
Compliance with Standards and Maintenance Requirements	60.11(a) thru (d), and (f)		EU 001 - 004	General compliance requirements.
Circumvention	60.12		EU 001 - 004	Cannot conceal an emission that would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	60.13		EU 001 - 004	Requirements for CEMS and monitoring devices.
General notification and reporting requirements	60.19		EU 001 - 004	General procedure regarding reporting deadlines.
40 CFR Part 60 Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units				
Notification	60.48c(a)			Notification requirements for fuel gas heater
Recordkeeping	40.48c(g)			Recordkeeping requirements for fuel gas heater
40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines				
Standard for Nitrogen Oxides	60.332		EU 001 - 004	Specifies formula for determining allowable nitrogen oxide emission limit.
Standard for Sulfur Dioxide	60.333		EU 001 - 004	Specifies standard for sulfur dioxide emissions.
Monitoring Requirements	60.334(b)(2) and (c)		EU 001 - 004	Specifies monitoring requirements where supply of fuel does not include intermediate bulk storage. Allows for custom monitoring schedule.
Test methods and Procedures	60.335		EU 001 - 004	Specifies test methods and procedures.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, H, I, J, L, M, M, N, O, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements that are applicable to Vandolah Power Project.

Table E-1. *Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project*

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, J, L, M, N, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, FF, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV,XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS, TTTTT, and WWWWW		X		None of the listed NESHAPS' contain requirements that are applicable to Vandolah Power Project.
40 CFR Part 64 - Compliance Assurance Monitoring		X		The combustion turbines are not covered by this rule since they lack post-combustion controls.
40 CFR Part 72 - Acid Rain Program Permits				
40 CFR Part 72 Subpart A - Acid Rain Program General Provisions				
Standard Requirements	72.9		EU 001 - 004	General acid rain requirements
40 CFR Part 72 Subpart B - Designated Representative				
Designated Representative	72.20 - 72.25		EU 001 - 004	General requirements pertaining to the designated representative.
40 CFR Part 72 Subpart C - Acid Rain Permit Application				
Requirements to Apply	72.30(a)		EU 001 - 004	Requirements to submit a complete Acid Rain permit by the applicable deadline.
	72.30(b)(1)(i)		EU 001 - 004	Deadline to submit a complete Acid Rain permit application.
	72.30(c)		EU 001 - 004	Requirements to submit a complete Acid Rain permit application for each source with an affected unit at least six months prior to the expiration of an existing Acid Rain permit governing the unit during phase II or such longer time as may be approved under Part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted.

Table E-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
	72.30(d)		EU 001 - 004	Requirements to submit an original and three copies of all permit applications to EPA.
Information for Acid Rain Permit Applications	72.31		EU 001 - 004	General permit application requirements.
40 CFR Part 72 Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	72.40		EU 001 - 004	General Compliance Plan Requirements
40 CFR Part 72 Subpart E - Acid Rain Permit Contents				
Permit Shield	72.51		EU 001 - 004	Units operating in compliance with Acid Rain Permit are deemed to be operating in compliance with Acid Rain Program
40 CFR Part 72 Subpart H - Permit Revisions				
Fast-Track Modifications	72.82		EU 001 - 004	Procedures for fast-track modificationsto Acid Rain Permits.
40 CFR Part 72 Subpart I - Compliance Certification				
Annual Compliance Certification Report	72.90		EU 001 - 004	Requirement to submit an annual compliance report.
40 CFR Part 75 - Continuous Emission Monitoring				
40 CFR Part 75 Subpart A - General				
Prohibitions	75.5		EU 001 - 004	General prohibitions.
40 CFR Part 75 Subpart B - Monitoring Provisions				
General Operating Requirements	75.10		EU 001 - 004	General monitoring requirements
Specific Provisions for Monitoring NOx Emissions	75.12		EU 001 - 004	NOx continuous monitoring requirements.
40 CFR Part 75 Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Requirements	75.20(a)		EU 001 - 004	Requires that monitoring systems meet initial certification requirements by the deadlines stipulated in 75.4.
	75.20(a)(1)		EU 001 - 004	Requires notification of certification test or retest dates at least 45 days prior to certification testing.
	75.20(a)(2)		EU 001 - 004	Requires submittal of certification application in accordance with 75.60.
	75.20(a)(5)		EU 001 - 004	Procedures to be used in the event that the agency issues a disapproval of certification application or certification status.
	75.20(c)(1) - (7), (9)		EU 001 - 004	Certification procedure requirements.
Quality Assurance and Quality Control Requirements	75.21		EU 001 - 004	General QA/QC requirements.
	75.22		EU 001 - 004	Specifies required test methods to be used for certification or recertification testing.
Out-Of-Control Periods	75.24		EU 001 - 004	Specifies out-of-control periods and the required actions to be taken when they occur.

Table E-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 75 Subpart D - Missing Data Substitution Procedures				
General Provisions	75.30		EU 001 - 004	General missing data requirements.
Initial Missing Data Procedures	75.31		EU 001 - 004	Missing data procedure requirements during the first 720 and 2,160 quality-assured monitor operating hours for SO2 pollutant concentration monitor and flow monitor/NOx CEMS, respectively.
Determination of Monitor Data Availability for Standard Missing Data Procedures	75.32		EU 001 - 004	Monitor data availability procedure requirements after the first 720 and 2,160 quality-assured monitor operating hours for SO2 pollutant concentration monitor and flow monitor/NOx CEMS, respectively.
Standard Missing Data Procedures	75.33		EU 001 - 004	Missing data substitution procedure requirements after the first 720 and 2,160 quality-assured monitor operating hours for SO2 pollutant concentration monitor and flow monitor/NOx CEMS, respectively.
40 CFR Part 75 Subpart E - Alternative Monitoring Systems				
Alternative Monitoring Systems	75.40 - 75.48		EU 001 - 004	Optional requirements for alternative monitoring systems.
40 CFR Part 75 Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	75.50		EU 001 - 004	General recordkeeping requirements.
Certification, Quality Assurance, and Quality Control Record Provisions	75.59		EU 001 - 004	General QA/QC recordkeeping requirements.
Monitoring Plan	75.53(a) - (c)		EU 001 - 004	Requirement to prepare and maintain a Monitoring Plan
40 CFR Part 75 Subpart G - Reporting Requirements				
General Provisions	75.60		EU 001 - 004	General reporting requirements.
Notification of Certification and Recertification Test Dates	75.61		EU 001 - 004	Requires written submittal of certification tests, recertification test, and reised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of certification ofr recertification testing. Notification of any proposed adjustmnet to certification testing dates must be provided at least 7 dbusiness days prior to the proposed date change.
Monitoring Plan	75.62		EU 001 - 004	Monitoring Plan required to be submitted no later than 45 days prior to the certification test.

Table E-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Certification or Recertification Application	75.63		EU 001 - 004	Requires submittal of a certification application within 30 days after completing the certification test.
Quarterly Reports	75.64(a)(1) - (5)		EU 001 - 004	Requirement to submit quarterly data report.
	75.64(b), (c), (d)		EU 001 - 004	Requirement to submit compliance certification in support of each quarterly data report. Requirement to submit quarterly reports in an electronic format to be specified by EPA.
	75.65		EU 001 - 004	Requirement of reports of excess opacity emissions to the applicable State (FDEP) agency in the format specified by the State agency.
40 CFR Part 77 - Excess Emissions				
Penalties for Excess Emissions of Sulfur Dioxide and Nitrogen Oxides	77.6		EU 001 - 004	Requirement to pay a penalty if excess emissions of SO2 or NOx occr at any affected unit during any year.
40 CFR Part 78 - Appeal Procedures for Acid Rain Program				
	78.1 - 78.20		EU 001 - 004	Optional appeal procedures for EPA Acid Rain program decisions.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards Requirements		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 68 - EPA Provisions for Chemical Accident Prevention				
General			Facilitywide	Requires compliance with risk management planning regulations.
Hazard Assessment			Facilitywide	Defines hazard assessment requirements.
Program 2 Prevention Program			Facilitywide	Defines elements of the prevention program.
Program 3 Prevention Program		X		
Emergency Response			Facilitywide	Defines elements of the emergency response plan.
Regulated Substances for Accidential Release Prevention			Facilitywide	Defines elements subject to regulation.
Risk Management Plan			Facilitywide	Defines elements of the risk management plan.
Other Requirements			Facilitywide	Defines certain recordkeeping requirements.

Table E-1. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 58, 62, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, and 90		X		The listed regulations do not contain any requirements that are applicable to Vandolah Power Project.
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		Vandolah Power Project does not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Vandolah Power Project does not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing is conducted off-site by persons who comply with Subpart B requirements.
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Vandolah Power Project does not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Vandolah Power Project does not produce any products containing ozone depleting substances.

ECT, 2006.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C.[1]		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040(1)(a), and (b), F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits and Other Authoriztions	62-4.050, F.A.C.		X		Specifications of forms, certifications, fees, etc.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C.	X			Establishes standard procedures for FDEP. Requirement is not applicable to the facility.
Modification of Permit Conditions	62-4.080, F.A.C	X			A Title V permit condition modification is not requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.430(3), F.A.C.
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.
Financial Responsibility	62-4.110, F.A.C.		X		The Department may require an applicant to submit proof of financial reaponsibility and/or post a bond.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not being requested..
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Permit Review	62-4.150, F.A.C.	X			Failure to request a hearing within 14 days of proposed or final Agency action on a permit application shall be deemed a waiver to the right to an administrative hearing.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Conditions	62-4.160(2), (8), and (14), F.A.C.		X		Lists general conditions that must be contained in permits. Specifically, 62-4.160(2) states that deviations from original specifications or conditions of the permit are not allowed. Under 62-4.160(8) applicants must report the cause and duration of non-conpliance, and 62-4.160(14) requires permit and monitoring records must be maintained at the facility and supplied to FDEP upon request.
Chapter 62-4, F.A.C. - Part II Specific Permits; Requirements					
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits.
Chapter 62-204, F.A.C. - Air Pollution Control - General Provisions					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.	X			Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W. Air quality modeling is not required for Title V permit applications.
Federal Regulations Adopted by Reference	62-204.800(8), F.A.C.			EU 001 - 004	All Federal Regulations cited in the rules by the Department are adopted and incorportated by reference. Specifically, the new source performance standard contained in 40 CFR 60 Subparts Dc and GG applies to the fuel gas heater and the stationary gas turbines, respectively.
Federal Regulations Adopted by Reference	62-204.800(10) and (11), F.A.C.		X		National Emissions Standards for Hazardous Air Pollutants; see Table A-5a for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800(12), F.A.C.	X			Complaince Assurance Monitoring Program; see Table A-5a for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800(15), F.A.C.		X		Part 70 State Operating Permit Program; see Table A-5a for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800(16) to (21), F.A.C.			EU 001 - 004	Acid Rain Program; see Table A-5a for detailed federal regulatory citations.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Federal Regulations Adopted by Reference	62-204.800(23), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-5a for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Permits Required	62-210.300, F.A.C., except 62-210.300(1) and (4), F.A.C.		X		Air operation permit required, with the exception of certain facilities and sources. Startup notification required if a permitted source has been shut down for more than 1 year.
Air Construction Permits	62-210.300(1), F.A.C.	X			Application is for Title V operating permit renewal. A construction permit is not requested in this application.
Emission Unit Reclassification	62-210.300(5), (6), & (7) F.A.C.		X		Notification of startup, emission unit reclassification, and transfer of air permit **(potential future requirements).**
Public Notice and Comment	62-210.350(1), F.A.C.		X		All permit applicants, including those for renewals and revisions, are required to publish notice of proposed agency action **(future requirement).**
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.	X			PSD and nonattainment area NSR application not required for permit renewal application.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.-A.C.		X		Notice requirements for Title V operating permits, renewals, and revisions **(future requirement).**
Administrative Permit Corrections	62-210.360, F.A.C.	X			Application is for initial Title V operating permit. An administrative permit correction is not requested in this application.
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Facility does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Title V sources are required to submit an annual operating report.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Stack Height Policy	62-210.550, F.A.C.	X			Limits credit in air dispersion studies to good engineering practice (GEP) stack heights.
Circumvention	62-210.650, F.A.C.		X		An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700, F.A.C.			EU 001 - 004	Excess emissions due to startup, shut down, and malfunction are permitted. Excess emissions due to malfunction must be reported. Excess emissions during soot blowing and load change are permitted with restrictions. **(potential future requirement)**
Forms and Instructions	62-210.900, F.A.C.		X		List required FDEP forms for stationary sources.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.	X			Air construction permit requirements, not applicable to Title V operating permit renewal applications.
Prevention of Significant Deterioration	62-212.400(7)(b), F.A.C.	X			The operation permit shall contain all operating conditions and provisions required under 62-212.400 and set forth in the original or amended construction permit.
Preconstruction Review for Nonattainment Areas	62-212.500, F.A.C.	X			Facility not located in any nonattainment area or nonattainment area of influence.
Air Emissions Bubble	62-212.710, F.A.C.	X			Contains no applicable requirements.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Responsible Official	62-213.202, F.A.C.		X		Title V sources must designate a responsible official.
Annual Emissions Fee	62-213.205, F.A.C.		X		Title V sources must pay an annual emissions fee.
Title V Air General Permits	62-213.300, F.A.C.	X			Not an eligible facility.
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. Lists changes for which a permit revision is required **(potential future requirement)**.
Concurrent Processing of Permit Applications	62-213.405, F.A.C.	X			No construction permit is being sought at this time.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			EU 001 - 004	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.		X		Defines the conditions under which emissions trading is allowable.
Permit Applications	62-213.420(3), and (4), F.A.C.		X		Title V operating permit renewal application must contain all the information specified by 62-213.420(3), F.A.C. and be certified by the responsible official.
Permit Issuance, Renewal, and Revision	62-213.430(3) and (6), F.A.C.		X		Permits being renewed are subject to the same requirements that apply to permit issuance. Permit renewals shall contain the information specified in 62-210.900(1) and 62-213.420(3), F.A.C. 420(6) contains criteria for defining insignificant emission units and activities.
Permit Content	62-213.440(1), and (2), F.A.C.		X		Any recording, monitoring, or reporting requirements that are time specific shall be in accordance with the effective date of the permit i.e., January 1, 1999, which defines day one. Defines schedule for submitting certification forms or compliance schedules.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions.
Forms and Instructions	62-213.900(1), (7), and (8), F.A.C.		X		Lists applicable forms such as "Major Air Pollution Source Annual Emissions Fee," Statement of Compliance," and "Responsible Official Notification."
Chapter 62-214 F.A.C. - Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	62-214.300, F.A.C.		X	EU 001 - 004	Facility includes Acid Rain units, therefore facility compliance with 62-213 and 62-214, F.A.C., is required.
Applications	62-214.320, F.A.C.		X	EU 001 - 004	Requires Title V sources having Acid Rain unit(s) to submit an Acid Rain Application to FDEP.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Acid Rain Compliance Plan and Compliance Options	62-214.330, F.A.C.			EU 001 - 004	Acid rain compliance plan must be submitted to the Department.
Exemptions	62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement).**
Certification	62-214.350, F.A.C.		X	EU 001 - 004	The designated representative must certify all Acid Rain submissions.
Department Action on Applications	62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	62-214.370, F.A.C.		X		Defines revision procedures and automatic amendments **(potential future requirement).**
Acid Rain Part Content	62-214.420, F.A.C.			EU 001 - 004	Defines content of Acid Rain Part.
Implementation and Termination of Compliance Options	62-214.430, F.A.C.		X		Defines permit activation and termination procedures **(potential future requirement).**
Chapter 62-252 - Gasoline Vapor Control					
Rules for gasoline vapor control equipment	62-252, F.A.C.	X			Facility not located in an ozone nonattainment area or an air quality maintenance area for ozone
Chapter 62-256, F.A.C. - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	62-256.300, F.A.C.[1]		X		Prohibits open burning.
Agricultural and Silvacultural Rires	62-256.400, F.A.C.	X			Contains no applicable requirements.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	62-256.500, F.A.C.[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	62-256.600, F.A.C.[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.	X			Contains no applicable requirements.
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos					

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Controls release of asbestos to the atmosphere and establishes fees.	62-257.301, .400, and .900, F.A.C.[1]		X		Requires notice and payment of fee for asbestos removal projects **(potential future requirement).**
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling					
Estabishes installation and proper use of motor vehicle refrigerant recycling equipment.	62-281.100, F.A.C.			Vehicle Fleet Maintenance	Servicing of motor vehicle air conditioners and vehicle maintenance that may release refrigerants is conducted.
Chapter 62-296 - Stationary Sources - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department. No such devices have been required at Vandolah Power Project.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.[1]		X		Objectionable odor release is -prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	62-296.320(3), F.A.C.[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.		X		Facility does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Sulfuric Acid Plants	62-296.402(2)(a), (b), & (c), F.A.C.	X			Standards for new sulfuric acid plants, i.e., 10% opacity, 4 lb of sulfur dioxide per ton of acid produced, and 0.15 lb of acid mist per ton of acid produced.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Existing Fossil Fuel Fired Steam Generators with More Than 250 MMBtu/hr Heat Input	62-296.405(1)(a), (b), (c)1.j. and (c)3., (e)1, 2 and 3, and (f)1.b., and g., F.A.C.	X			No applicable units at facility.
New and Existing Fossil Fuel Fired Steam Generators with Less Than 250 MMBtu/hr Heat Input	62-296.406(1), (2), (3), F.A.C.	X			No applicable units at facility.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.404 and 62-296.407 through 62-296.417, F.A.C.	X			No applicable unit at facility.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Facility is not located in an ozone nonattain-ment area or an ozone air quality maintenance area.
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Facility is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (Broward, Dade and Palm Beach Counties).
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Facility not located in a lead nonattainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	62-296.700 through 62-296.712, F.A.C.	X			Facility not located in a PM nonattainment area or a PM air quality maintenance area.
Chapter 62-297, Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Test Requirements	62-297.310(1) through (8), F.A.C.			EU 001 - 004	Specifies general compliance test requirements including the number of runs, operating rates during testing, emission rate calculation, applicable test procedures, determination of process variables, required stack sampling facilities, frequency of tests, and content of test reports.

Table E-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements for the Vandolah Power Project

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Compliance Test Methods	62-297.401, F.A.C.	X			List methods to be used for compliance testing.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains other test procedures adopted by reference.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F-.A.C.	X			Contains no applicable requirements.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains performance specifications for continuous emissions monitoring.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

[1] State requirement only; not federally enforceable.

ECT, 2006.

ATTACHMENT F

COMPLIANCE REPORT AND PLAN

BEST AVAILABLE COPY

1202
2006

1/18/07

Vandolah

January 17, 2007

Joel Smolen
Air Compliance Supervisor
Florida Department of Environmental Protection (FDEP)
13051 N. Telecom Parkway
Temple Terrace, Fl. 33637
Phone: 813-632-7600
Fax: 813-632-7665

Re: Vandolah Power Company, LLC
Facility ID: 0490043; ORIS Code: 55415; Title V Permit: 0490043-003-AV
Title V Statement of Compliance - 2006

Dear Mr. Smolen:

Vandolah Power Company respectfully submits the 2006 "Statement of Compliance – Title V Source" form and support information for the Vandolah Power Project located near Wauchula, Hardee County, Florida.

If there are any questions regarding this submittal, please do not hesitate to contact me at (863)773-2277 x2222 (e-mail: doug.jensen@northernstargen.com) or Chris Coombs at (863) 773-2277 x2228 (e-mail: chris.coombs@northernstargen.com).

Sincerely,

Douglas A. Jensen
Plant Manager

cc:

- Ms. Rosalyn Hughes – US EPA Region 4, Air Enforcement Section, 61 Forsyth Street, Atlanta, GA 30303-8960 [tel 404-562-9206]

- Mr. Chris Coombs – Vandolah Power Company – EHS Manager

Department of Environmental Protection

Division of Air Resource Management

STATEMENT OF COMPLIANCE - TITLE V SOURCE

REASON FOR SUBMISSION (Check one to indicate why this statement of compliance is being submitted)

☑ Annual Requirement	☐ Transfer of Permit	☐ Permanent Facility Shutdown

REPORTING PERIOD*	REPORT DEADLINE**
January 1 through December 31 of 2006 (year)	February 28, 2007

*The statement of compliance must cover all conditions that were in effect during the indicated reporting period, including any conditions that were added, deleted, or changed through permit revision.
**See Rule 62-213.440(3)(a)2., F.A.C.

Facility Owner/Company Name: Vandolah Power Company, LLC

Site Name: Vandolah Power Project Facility ID No. 0490043 County: HARDEE

COMPLIANCE STATEMENT (Check only one of the following three options)

XX A. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, and there were no reportable incidents of deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above.

____ B. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part; however, there were one or more reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each incident of deviation, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

____ C. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, EXCEPT those identified in the pages attached to this report and any reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number (note whether the permit condition has been added, deleted, or changed during certification period).
3. Description of the requirement of the permit condition.
4. Basis for the determination of noncompliance (for monitored parameters, indicate whether monitoring was continuous, i.e., recorded at least every 15 minutes, or intermittent).
5. Beginning and ending dates of periods of noncompliance.
6. Identification of the probable cause of noncompliance and description of corrective action or preventative measures implemented.
7. Dates of any reports previously submitted identifying this incident of noncompliance.

For each incident of deviation, as described in paragraph **B.** above, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am a responsible official (Title V air permit application or responsible official notification form on file with the Department) of the Title V source for which this document is being submitted. With respect to all matters other than Acid Rain program requirements, I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

(Signature of Title V Source Responsible Official) 1-16-07 *(Date)*

Name: **Douglas A. Jensen** Title: **Vandolah Plant Manager**

DESIGNATED REPRESENTATIVE CERTIFICATION (only applicable to Acid Rain source)

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

(Signature of Acid Rain Source Designated Representative) 1-16-07 *(Date)*

Name: **Douglas A. Jensen** Title: **Vandolah Plant Manager**

{Note: Attachments, if required, are created by a responsible official or designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by a responsible official or designated representative when elaboration is required for clarity. This report is to be submitted to both the compliance authority (DEP district or local air program) and the U.S. Environmental Protection Agency(EPA) (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

ATTACHMENT G

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

ATTACHMENT G

VANDOLAH POWER COMPANY, LLC
VANDOLAH POWER PROJECT

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

The following summarizes the requested changes to the current Title V Air Operation Permit:

- Section I, Subsection A—Administratively corrected stack height listed in permit from 60 feet to 75 feet.

- Section I, Subsection B—Remove EU ID No. 005-006, Two 2.8 Million Gallon Fuel Oil Storage Tanks and list under Insignificant Units and/or Activities. These emissions units were previously subject to NSPS 40 CFR part 60 Subpart Kb. This regulation does not apply to these emissions units effective October 15, 2003.

- Section III, Permit Condition A.5—Revise maximum heat input rates from 1,612 MMBtu/hr, while firing natural gas and 1,806 MMBtu/hr, while firing distillate fuel oil, based on lower heating value (LHV) and ISO conditions to 1,854 MMBtu/hr, while firing natural gas and 1,969 MMBtu/hr, while firing distillate fuel oil, based on higher heating value (HHV) and at ambient temperature of 32 degrees Fahrenheit. These heat input values are consistent with the heat input values presented in the original Title V permit application. A copy of the design information has been provided as Attachment L for your convenience. This requested change does not affect any permitted emission limit.

- Section III, Permit Condition A.5—Add the following FDEP standard language:

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

- Section III, Permit Condition A.23—Added the following language:

For each combustion turbine that fires distillate oil for less than 400 hours during the previous fiscal year, the annual performance (compliance) tests for firing distillate oil for the current fiscal year of operation are not required.

- Section III, Permit Condition A.46—Delete reference to requirement that fuel vendor provide analysis of nitrogen content of distillate fuel oil.
- Section IV—Revised EPA ID numbers of combustion turbines from CT1 thru CT4 to GT101, GT201, GT301, and GT401 to be consistent with EDR reporting.

An electronic version of the Title V operating permit, which incorporates the above requested changes using the track changes feature, can be provided upon request.

REQUESTED CHANGES TO LIST OF INSIGNIFICANT ACTIVITIES

- Updated List of Insignificant Activities (refer to Attachment D).

An electronic version of the updated List of Insignificant Activities can be provided upon request.

ATTACHMENT H

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT H-1

Typical Natural Gas Composition

Component	Percent (by volume)
<u>Gas Composition</u>	
Hexane+	0.05
Propane	0.40
I-butane	0.09
N-butane	0.10
Pentane	0.06
Nitrogen	0.44
Methane	96.00
CO_2	0.88
Ethane	2.15
<u>Other Characteristics</u>	
Heat content	1,035 Btu/ft^3 with 14.73 psia, dry
Specific gravity	0.587
Sulfur content (maximum)	1.0 gr/100 scf

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

Source: FGT Gulfstream Osceola Station, 2007.

ATTACHMENT H-2

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Density, lb/gal (average)	7.05
Heat of combustion, Btu/lb (average)	
Gross	19,398
Net	18,300
Hydrogen, percent by weight (average)	12.65
Carbon, percent by weight (average)	87.10
Nitrogen, percent by weight (average)	0.02
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Trace constituents, ppm	
Sodium	<0.1
Vanadium	<0.1
Potassium	<0.1
Lead	<0.1
Calcium	<0.1
Magnesium	<0.1

Note: Btu/lb = British thermal units per pound.
lb/gal = pounds per gallon.
ppm = parts per million.

Source: Golder Associates, 1998.
ECT, 2007.

ATTACHMENT I

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

GEK 106852B
Revised, September 2001
Replaces GFD26Q00

GE Power Systems
Gas Turbine

Fuel Gas Control System (DLN_x 2.6)

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-l 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.

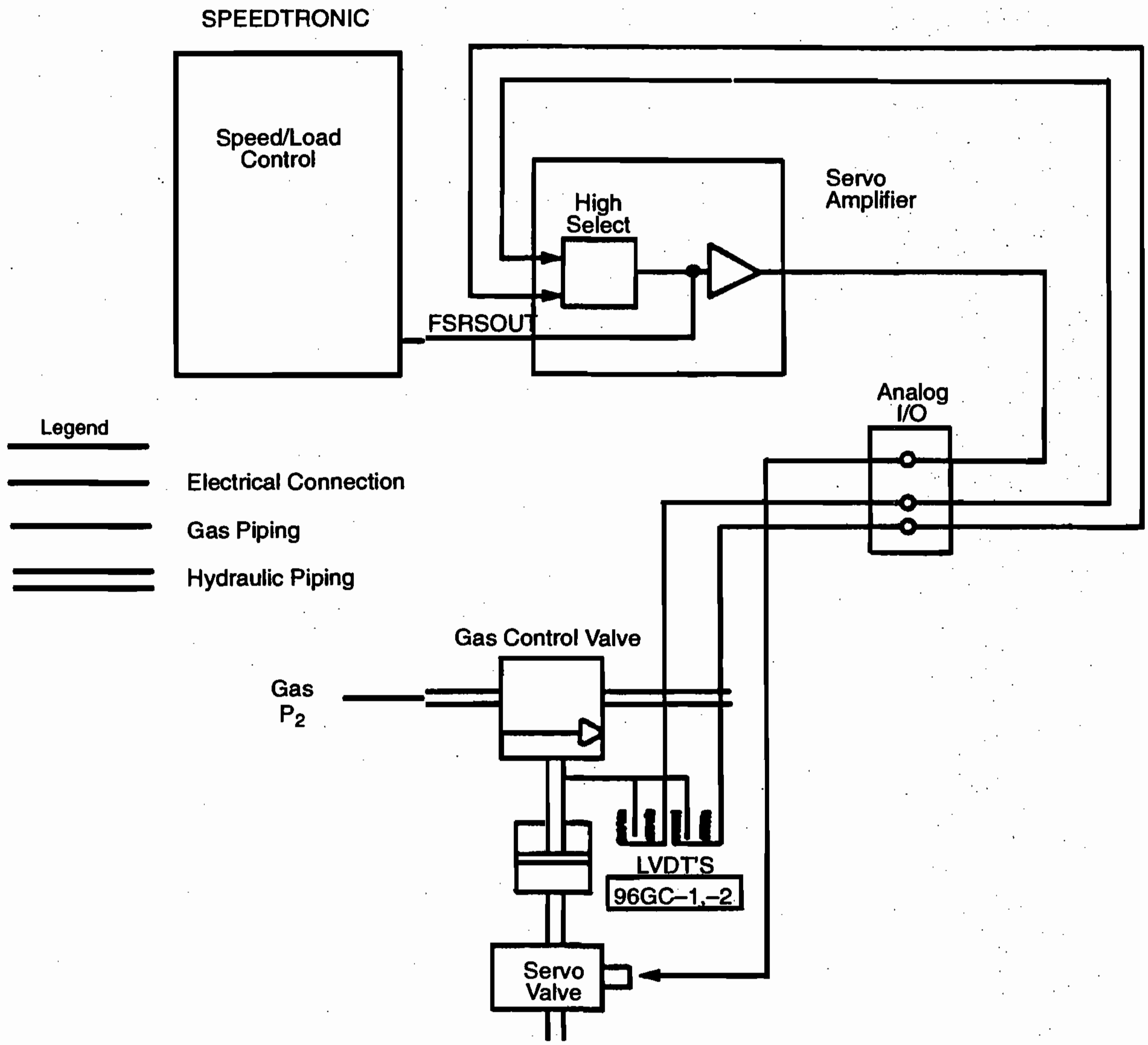


Figure 1. Gas Control Valve Control Schematic.

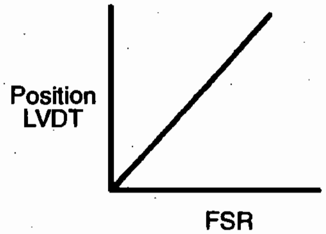


Figure 2. Gas Control Valve Position Loop Calibration.

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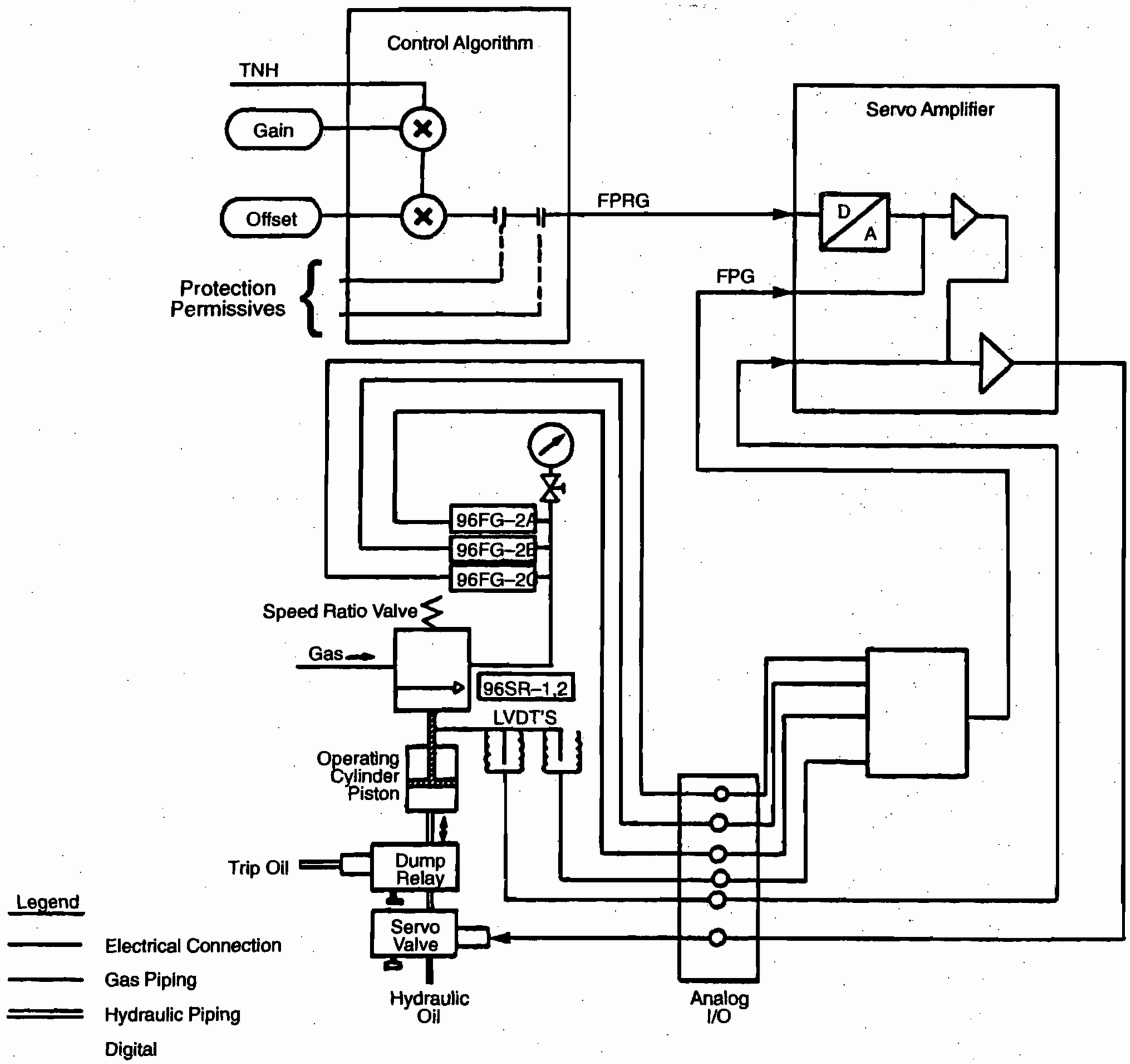

Figure 3. Speed Ratio/Stop Valve Control Schematic.

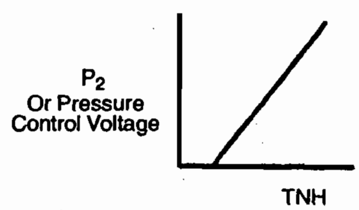

Figure 4. Speed Ratio Valve Pressure Calibration.

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GEK 106844
March 1998
Replaces DLN2600

GE Power Systems
Gas Turbine

Dry Low NO_x 2.6 System Operation

I. GENERAL

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

II. GAS FUEL SYSTEM

The DLN 2.6 Combustion system consists of six fuel nozzles per combustion can, each operating as a fully premixed combustor, five located radially, one located in the center. The center nozzle, identified as PM1, (PreMix 1), two outer nozzles located adjacent to the crossfire tubes, identified as PM2, (PreMix 2), and the remaining three outer nozzles, identified as PM3, (PreMix 3). Another fuel passage, located in the air-flow upstream of the premix nozzles, circumferentially around the combustion can, is identified as the quaternary fuel pegs, (refer to figure 1).

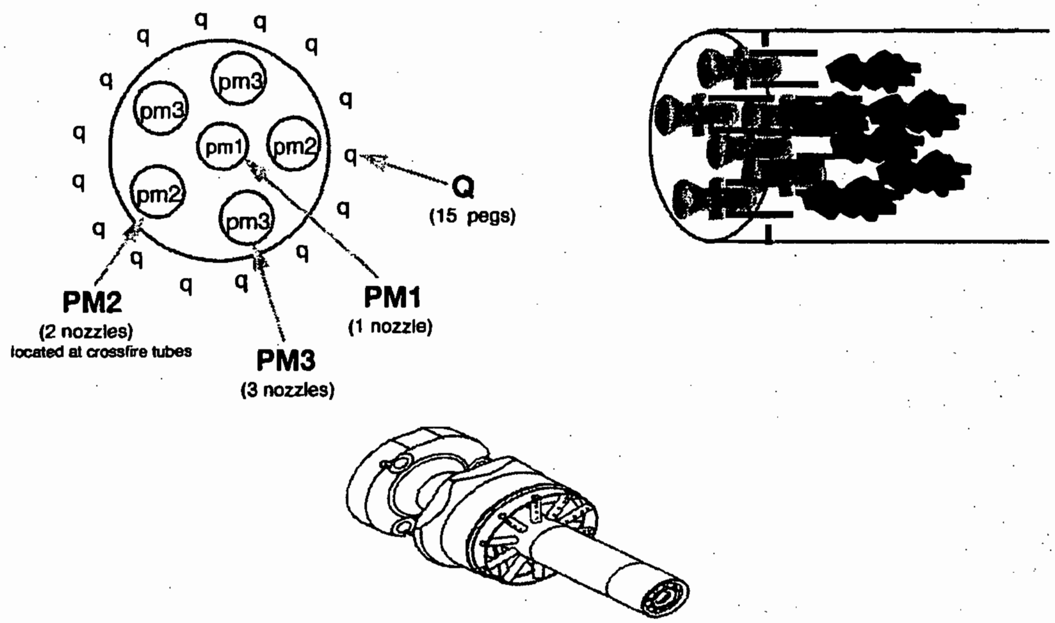

Figure 1. DLN2.6 Fuel Nozzle Arrangement

The fuel flow to the six fuel nozzles and quaternary pegs are controlled by four independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one, (PM1), gas control valve two (PM2), gas control valve three, (PM3), and gas control valve four, (Quat). (Refer to figure 2.)

The stop/ratio valve (SRV) is designed to maintain a predetermined pressure, (P2), at the inlet of the gas control valves. Gas control valves one through four, (GCV1–4), regulate the desired gas fuel flow delivered to the turbine in response to the command signal FSR, (Fuel Stroke Reference), from the SPEEDTRONIC panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. This flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software.

The stop ratio valve and gas control valves are monitored for their ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to warn the operator. If the condition persists for an extended amount of time, the turbine will be tripped and another alarm will annunciate the trip.

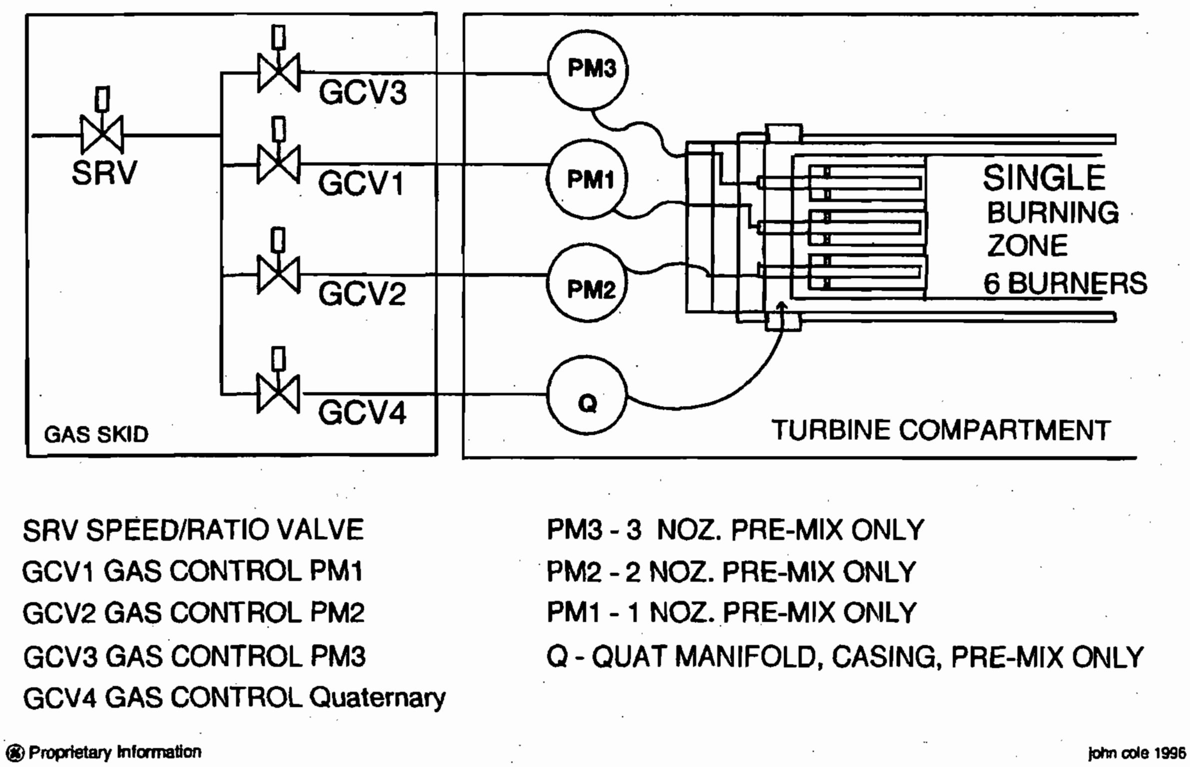

FIGURE 2. Gas Fuel System

III. GAS FUEL OPERATION

The DLN 2.6 fuel system operation is a fully automated, sequencing the combustion system through a number of staging modes prior to reaching full load. Figure three represents typical operation sequence, from firing to full load fuel flow staging associated with DLN–2.6 operation, and a typical shutdown fuel staging sequence from full load to unit flame out at part speed. As illustrated, the primary controlling parameter for fuel staging is the calculated combustion reference temperature (TTRF1), which will be discussed later in this document. Other DLN 2.6 operation influencing parameters available to the operator are the selection of IGV temperature control "on" or "off", and the selection of inlet bleed heat "on" or "off". To achieve maximum exhaust temperature as well as an expanded load range for optimal emission, IGV temperature control should be selected "ON", and inlet bleed heat should be selected "ON". Temperature control and Inlet bleed heat operation will be discussed later in this document.

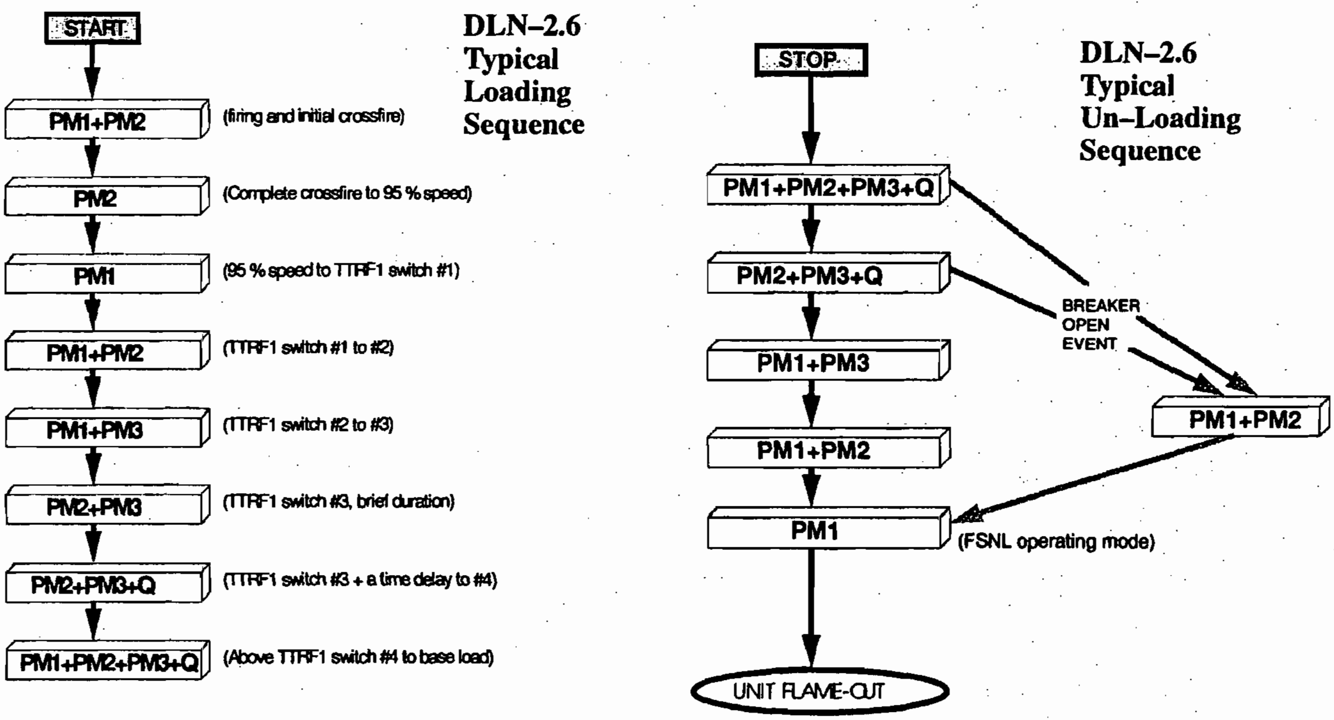

FIGURE 3. DLN2.6

DLN 2.6 operational mode is displayed on the main display as well as the DLN display. Operational mode is defined as the sum of the nozzles being delivered fuel, therefore, if PM1 and PM3 are fueled, the unit is in Mode 4, likewise, if PM2 and PM3 are fueled, the unit is in Mode 5. When the quaternary passages are fueled, a Q is added to the mode number.

IV. CHAMBER ARRANGEMENT

The 7F machine employs 14 combustors while the 9F employs 18 similar but slightly larger combustors. For each machine there are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent combustors. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi–nozzle cap assembly, liner assembly, and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion can, porting fuel to casing injection pegs located radially around the casing. Figure 4 represents the chamber arrangement

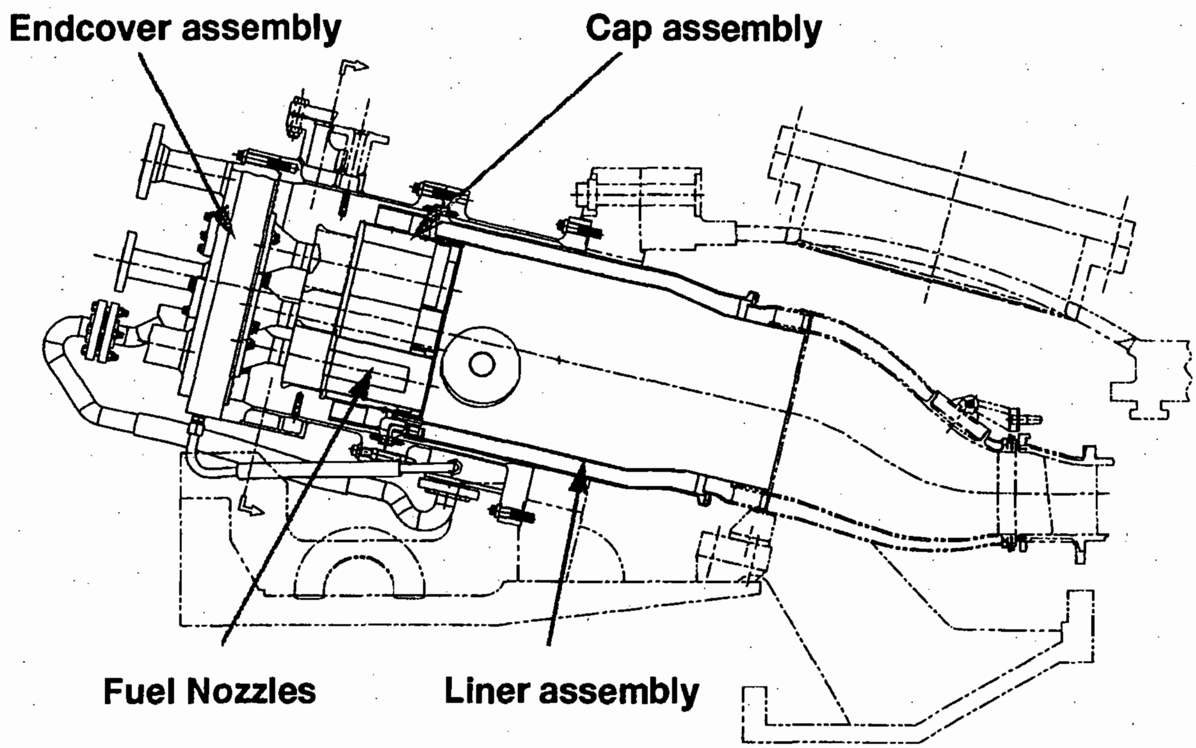

Figure 4. 7FA DLN–2 Combustor

V. COMBUSTION REFERENCE TEMPERATURE.

The combustion reference temperature signal, (TTRF1), is generated by a calculation in the DLN–2.6 control software. This calculated temperature represents a reference for combustor mode sequencing and fuel split scheduling, but not unit load control. It should be noted that TTRF1 is not a true indication of actual machine firing temperature, only a reference for DLN 2.6 mode transition sequencing. A careful checkout of the combustion reference temperature during initial commissioning is required.

VI. DLN–2.6 INLET GUIDE VANE OPERATION

The DLN–2.6 combustor emission performance is sensitive to changes in fuel to air ratio. The combustor was designed according to the airflow regulation scheme used with inlet guide vane, (IGV), temperature control. Optimal combustor operation is crucially dependent upon proper operation along the predetermined temperature control scheme. Controlled fuel scheduling will be dependent upon the state of IGV temperature control. IGV temperature control on can also be referred to as combined cycle operation while IGV temperature control off is referred to as simple cycle operation.

VII. DLN–2.6 INLET BLEED HEAT

Operation of the gas turbine with reduced minimum IGV settings can be used to extend the Premix operating region by 20 – 30% of base load. Reducing the minimum IGV angle allows the combustor to operate at a firing temperature high enough to achieve optimal emissions.

Inlet bleed heating, (IBH), through the use of recirculated compressor discharge airflow, is necessary when operating with reduced IGV angles. Inlet heating protects the compressor from stall by relieving the discharge pressure and by increasing the inlet air stream temperature. Other benefits include anti-icing protection due to increased pressure drop across the IGV's.

The inlet bleed heat system regulates compressor discharge bleed flow through a control valve and into a manifold located in the compressor inlet air stream. The control valve varies the inlet heating air flow as a function of IGV angle. At minimum IGV angles the inlet bleed flow is controlled to a maximum of 5.0% of the total compressor discharge flow. As the IGV's are opened at higher loads, the inlet bleed flow will proportionally decrease until shut off.

The IBH control valve is monitored for its ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to warn the operator. If the condition persist for an additional amount of time, the inlet bleed heat system will be tripped and the IGV's minimum reference will be raised to the default value.

The IBH system monitors the temperature rise in the compressor inlet airflow. This temperature rise serves as an indication of bleed flow. Failure to detect a sufficient temperature rise in a set amount of time will cause the inlet bleed heat system to be tripped and an alarm annunciated.

VIII. FLAME DETECTION

Reliable detection of the flame location in the DLN–2.6 system is critical to the control of the combustion process and to the protection of the gas turbine hardware. Four flame detectors in separate combustion chambers around the gas turbine are mounted to detect flame in all modes of operation. The signals from these flame detectors are processed in control logic and used for various control and protection functions.

IX. IGNITION SYSTEM

Two spark plugs located in different combustion chambers are used to ignite fuel flow. These spark plugs are energized to ignite fuel during start–up only, at firing speed. Flame is propagated to those combustion chambers without spark plugs through crossfire tubes that connect adjacent combustion chambers around the gas turbine.

X. CONTINGENCY OPERATION

A. Unit Trip

In the event of a unit trip, the gas fuel system will be shut down by deactivating the dump valves on the SRV and GCV's. This will allow the hydraulic fluid which activates the valve open to be ported to drain, while fluid is ported from hydraulic supply to close the valve, with assistance from the spring force.

B. False Start

During a false start, where flame is not established in the four monitored combustion chambers after 10 seconds, the stop ratio valve, (SRV) and gas control valves, (GCV's) are shut and the unit is run through a second unit purge cycle. At the end of this purge cycle, fuel is admitted and firing is again attempted. If the second attempt is unsuccessful in maintaining flame, the unit is tripped and the SRV and GCV's close.

XI. DLN–2.6 DISPLAY MESSAGES

The following display messages will appear on the SPEEDTRONIC control panel CRT in order to inform the operator of the current combustion mode of operation:

Mode 1 (or M1)

Mode 2 (or M2)

Mode 3 (or M3)

Mode 4 (or M4)

Mode 5 (or M5)

Mode 5Q (or M5Q)

Mode 6Q (or M6Q)

XII. DLN–2.6 SYSTEM ANNUNCIATOR TROUBLESHOOTING CHART

The following is a list of additional alarms and corrective actions for a gas turbine supplied with DLN–2.6 and related systems. This list is intended to be a supplement to the Annunciator chart contained in the standard gas turbine operating procedures.

XIII. DLN–2.6 ALARMS

Alarm Message	Cause	Action
DRY LOW NOX–2 SYSTEM TROUBLE TRIP (L4DLNT_ALM)	DLN SYSTEM FAULT, TRIP IS REQUIRED.	CHECK DLN SYSTEM TRIPS AND ALL OTHER ANNUNCIATED ALARMS
DRY LOW NOX–2 SYSTEM FAULT – FIRED SHUTDOWN (L94DLN_ALM)	DLN SYSTEM FAULT, UNSAFE TO OPERATE AT CURRENT LOAD POINT	CHECK DLN SYSTEM SHUTDOWNS AND ALL OTHER ANNUNCIATED ALARMS
GAS FUEL INTERVALVE PRESSURE TROUBLE	INTERVALVE PRESSURE OUT OF LIMITS	EXAMINE P2 PRESSURE TRANSDUCERS
GAS FUEL SUPPLY PRESSURE LOW ALARM (L63FGL_ALM)	FUEL SUPPLY PRESSURE BELOW MINIMUM REQUIRED	CHECK GAS SUPPLY PRESSURE, CLOGGED FILTER/SEPARATOR
NO INLET HEATING AIR FLOW DETECTED	LACK OF TEMPERATURE RISE AT INLET BELL– MOUTH WITH BLEED HEAT ENABLED	VERIFY MANUAL ISOLATION VALVE IS OPEN, VERIFY CONTROL VALVE OPERATION CHECK INLET THERMOCOUPLES
BLEED HEAT DRAIN VALVE FAIL TO CLOSE	IBH DRAIN VALVE STUCK OR FAULTY POSITION FEEDBACK	INSPECT VALVE, VERIFY POSITION, CHECK POSITION FEEDBACK
BLEED HEAT VALVE POSITION TROUBLE	IBH CONTROL VALVE STUCK OR FAULTY POSITION FEEDBACK	INSPECT VALVE, VERIFY POSITION, CHECK POSITION FEEDBACK
BLEED HEAT SYS NOT OPERATIONAL – TRIP	CONTROL VALVE STUCK CLOSED OR FAULTY INLET THERMOCOUPLE READINGS MANUAL ISOLATION/STOP VALVE MAY BE CLOSED	OBSERVE THE CONTROL STROKE AND CHECK THE INLET THERMOCOUPLES. CHECK THE MANUAL ISOLATION VALVE
GCV1 NOT FOLLOWING REF ALARM	GCV1 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION	EXAMINE GCV1 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV1 NOT FOLLOWING REF TRIP	GCV1 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION FOR AN EXTENDED PERIOD	EXAMINE GCV1 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV1 POSITION TROUBLE	GCV1 SERVO TROUBLE, SERVO CURRENT EXCESSIVE, LVDT DRIFTING, VALVE DRIFTING	EXAMINE GCV1 SERVO VALVE AND LVDT's FOR PROPER OPERATION
GCV2 NOT FOLLOWING REF ALARM	GCV2 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION	EXAMINE GCV2 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV2 NOT FOLLOWING REF TRIP	GCV2 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION FOR AN EXTENDED PERIOD	EXAMINE GCV2 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE

Alarm Message	Cause	Action
GCV2 POSITION TROUBLE	GCV2 SERVO TROUBLE, SERVO CURRENT EXCESSIVE, LVDT DRIFTING, VALVE DRIFTING	EXAMINE GCV2 SERVO VALVE AND LVDT'S FOR PROPER OPERATION
GCV3 NOT FOLLOWING REF ALARM	GCV3 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION	EXAMINE GCV3 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV3 NOT FOLLOWING REF TRIP	GCV3 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION FOR AN EXTENDED PERIOD	EXAMINE GCV3 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV3 POSITION TROUBLE	GCV3 SERVO TROUBLE, SERVO CURRENT EXCESSIVE, LVDT DRIFTING, VALVE DRIFTING	EXAMINE GCV3 SERVO VALVE AND LVDT'S FOR PROPER OPERATION
GCV4 NOT FOLLOWING REF ALARM	GCV4 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION	EXAMINE GCV4 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV4 NOT FOLLOWING REF TRIP	GCV4 COMMAND SETPOINT DIFFERENT FROM ACTUAL POSITION FOR AN EXTENDED PERIOD	EXAMINE GCV4 FOR STICKY OPERATION, JAMMING AND LVDT TROUBLE
GCV4 POSITION TROUBLE	GCV4 SERVO TROUBLE, SERVO CURRENT EXCESSIVE, LVDT DRIFTING, VALVE DRIFTING	EXAMINE GCV4 SERVO VALVE AND LVDT'S FOR PROPER OPERATION
AMBIENT PRESSURE READING AT MAX LIMIT (L3CPRAH)	AMBIENT PRESSURE ABNORMALLY HIGH	VERIFY AMBIENT PRESSURE, CHECK AMBIENT PRESSURE TRANSDUCER FOR CALIBRATION
AMBIENT PRESSURE READING AT MIN. LIMIT (L3CPRAL)	AMBIENT PRESSURE ABNORMALLY LOW	VERIFY AMBIENT PRESSURE, CHECK AMBIENT PRESSURE TRANSDUCER FOR CALIBRATION
INLET DIFFERENTIAL PRESS READING AT MAX LIMIT (L3CPRIH)	INLET BELLMOUTH DIFFERENTIAL PRESSURE ABNORMALLY HIGH	VERIFY INLET BELLMOUTH DIFFERENTIAL PRESSURE, CHECK TRANSDUCER FOR PROPER CALIBRATION
INLET DIFFERENTIAL PRESS READING AT MIN. LIMIT (L3CPRIL)	INLET BELLMOUTH DIFFERENTIAL PRESSURE ABNORMALLY LOW	VERIFY INLET BELLMOUTH DIFFERENTIAL PRESSURE, CHECK TRANSDUCER FOR PROPER CALIBRATION

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ATTACHMENT J

PROCEDURES FOR STARTUP AND SHUTDOWN

GE Power Systems
Gas Turbine

Plant Operation

I. PLANT OPERATION— GAS TURBINE/GENERATOR

A. Introduction

The package power plant, as furnished for this installation, is comprised of a heavy duty gas turbine unit driving a generator. Also included on site are generator auxiliary equipment, turbine and generator control equipment and off–base skids for fire protection, air processing, compressor & turbine cleaning, cooling water, and exhaust frame blowers (as applicable), all essential to the overall operation of the plant.

The purpose of this writeup is to provide the operator with basic information for understanding the overall operation of this plant.

More operational information on the turbine, generator or auxiliary equipment can be found in the system descriptions on the equipment. Unit specific operation, settings and adjustments information is covered by the Control Specifications. In addition one–line diagrams, and control equipment/piping schematics are in the Outlines and Diagrams section.

B. General

The control system supplied with this equipment is designed to provide full or partially automatic, sequential programmed operation, as selected by the operator. During operation, running data can be selected and displayed for operator information and action. This important running data is displayed on both the turbine control panel, and gauge/indicator readings on the turbine equipment. Unit alarms are displayed on the control panel CRT for review and action by the operator.

C. Checks Prior to Operation

Prior to startup or following major maintenance work, it is essential to check all support systems, power sources and control devices for proper condition. These checks are dependent on individual station procedures requirements, but may include such areas as drain valves closed, power breakers in the on position, supply/isolation valves open, controls in start/operation positions, any tagged out equipment returned to normal state, all safety equipment in place.

D. Operation

Following confirmation of hardware state, the operator can set controls to the desired point of control by way of the turbine/generator control panels. With the selection of automatic operation, the operator can perform a single start signal at the turbine control panel and the entire power package will start, sequence through the crank, fire, accelerate steps to running speed, synchronize and load to a preset point, all without additional input from the operator. If a lower level of operation (such as crank, fire) is selected at the control panel, the unit will automatically advance to that point and maintain until further selections are made. The SPEEDTRONIC™ control system has been programmed to sequentially accomplish functions engineered to bring the power plant from a standstill to the selected point of operation. The turbine/generator control system also starts and stops base mounted and auxiliary equipment to supply necessary cooling, lubrication, fuel requirements and protection functions.

With automatic generator synchronization selected, the control system will read, compare and adjust turbine–generator speed and generator voltage, etc., to match the system requirements. The generator is then connected to the system by closure of the generator breaker or line breaker. Output from the turbine–generator set can be adjusted to meet distribution system needs (this can be accomplished by the system dispatcher when that function has been connected to the control system). Synchronization of the turbine–generator unit to the distribution system can be automatic, as stated above, or manual. In either case, relaying and control components compare and display on the control panel critical information useful in the proper connection of this unit to the system. In the manual synchronization mode it is the operator's responsibility to adjust turbine–generator speed and generator voltage, etc., to match requirements before closing breaker at proper time.

Unit output is limited by turbine exhaust temperature constraints. As ambient temperatures change, the control system will automatically adjust fuel flow to the turbine to maintain exhaust temperature control setpoint, with corresponding change in output. Exhaust temperature control of the turbine–generator is an automatic function, programmed into the control system for protection of the equipment, and cannot be overridden.

In addition to the exhaust temperature control system, there are several other control and protection systems incorporated into the controls to ensure safe operation of this unit, these systems interact with each other automatically. They are described in the Control Support System section.

E. Shutdown

Normal shutdown (with automatic operation selected), is accomplished by giving the unit a stop signal at the control panel. The control system will unload the generator, open the generator breaker, decrease fuel to the turbine until flame can no longer be maintained in the combustion chambers, and decrease in speed to a standstill. At this point rotor turning function will be initiated. Also during the shutdown cycle, support systems will be activated or shutdown as required.

F. Special Operations

Special operations and abnormal operations are described in the Operation tab. These special modes of operation are unique to the equipment and needs of the site.

ATTACHMENT K

OPERATION AND MAINTENANCE PLAN

GER-3620G

GE Power Systems

Heavy-Duty Gas Turbine Operating and Maintenance Considerations

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Heavy-Duty Gas Turbine Operating and Maintenance Considerations

Introduction

Maintenance costs and availability are two of the most important concerns to the equipment owner. A maintenance program that optimizes the owner's costs and maximizes equipment availability must be instituted. For a maintenance program to be effective, owners must develop a general understanding of the relationship between their operating plans and priorities for the plant, the skill level of operating and maintenance personnel, and the manufacturer's recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting component life and proper operation of the equipment.

In this paper, operating and maintenance practices will be reviewed, with emphasis placed on types of inspections plus operating factors that influence maintenance schedules. A well-planned maintenance program will result in maximum equipment availability and optimal maintenance costs.

Note: The operating and maintenance discussions presented in this paper are generally applicable to all GE heavy-duty gas turbines; i.e., MS3000, 5000, 6000, 7000 and 9000. For purposes of illustration, the MS7001EA was chosen. Specific questions on a given machine should be directed to the local GE Energy Services representative.

Maintenance Planning

Advance planning for maintenance is a necessity for utility, industrial and cogeneration plants in order to minimize downtime. Also the correct performance of planned maintenance and inspection provides direct benefits in reduced forced outages and increased starting reliability, which in turn reduces unscheduled repair downtime. The primary factors which affect the maintenance planning process are shown in *Figure 1* and the owners' operating mode will determine how each factor is weighted.

Parts unique to the gas turbine requiring the most careful attention are those associated with

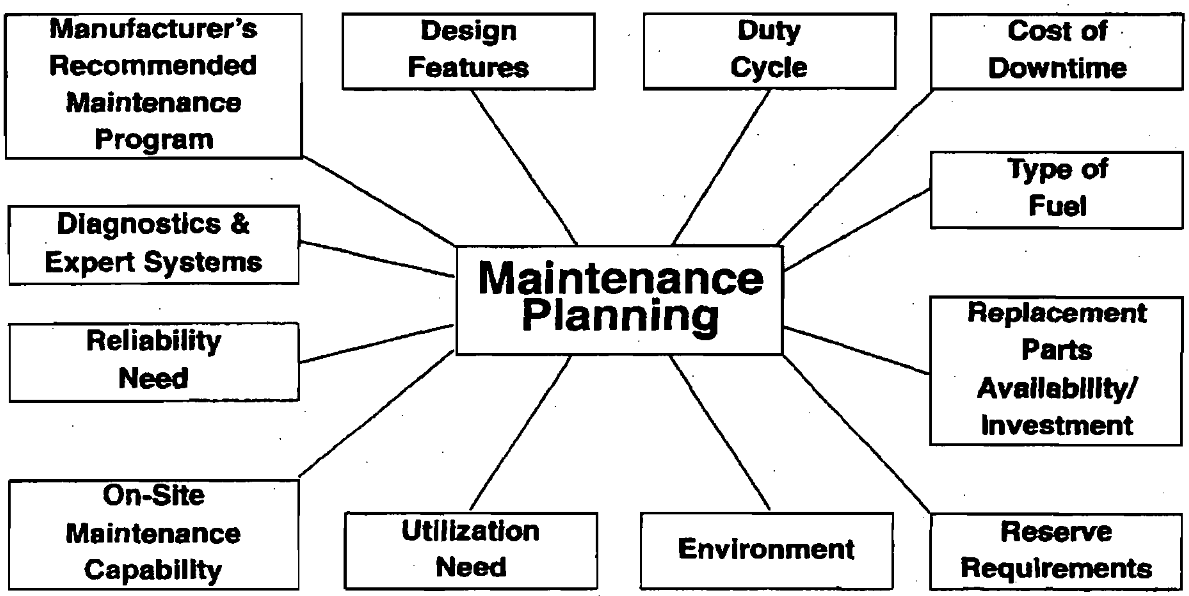

Figure 1: Key factors affecting maintenance planning

the combustion process together with those exposed to high temperatures from the hot gases discharged from the combustion system. They are called the hot-gas-path parts and include combustion liners, end caps, fuel nozzle assemblies, crossfire tubes, transition pieces, turbine nozzles, turbine stationary shrouds and turbine buckets.

The basic design and recommended maintenance of GE heavy-duty gas turbines are oriented toward:

- Maximum periods of operation between inspection and overhauls
- In-place, on-site inspection and maintenance
- Use of local trade skills to disassemble, inspect and re-assemble

In addition to maintenance of the basic gas turbine, the control devices, fuel metering equipment, gas turbine auxiliaries, load package, and other station auxiliaries also require periodic servicing.

It is apparent from the analysis of scheduled outages and forced outages (*Figure 2*) that the primary maintenance effort is attributed to five basic systems: controls and accessories, combustion, turbine, generator and balance-of-plant. The unavailability of controls and accessories is generally composed of short-duration outages, whereas conversely the other four systems are composed of fewer, but usually longer-duration outages.

The inspection and repair requirements, outlined in the Maintenance and Instructions Manual provided to each owner, lend themselves to establishing a pattern of inspections. In addition, supplementary information is provided through a system of Technical Information Letters. This updating of information, contained in the Maintenance and Instructions Manual, assures optimum installation, operation and maintenance of the turbine. Many of the Technical Information Letters contain advisory technical recommendations to resolve issues and improve the operation, mainte-

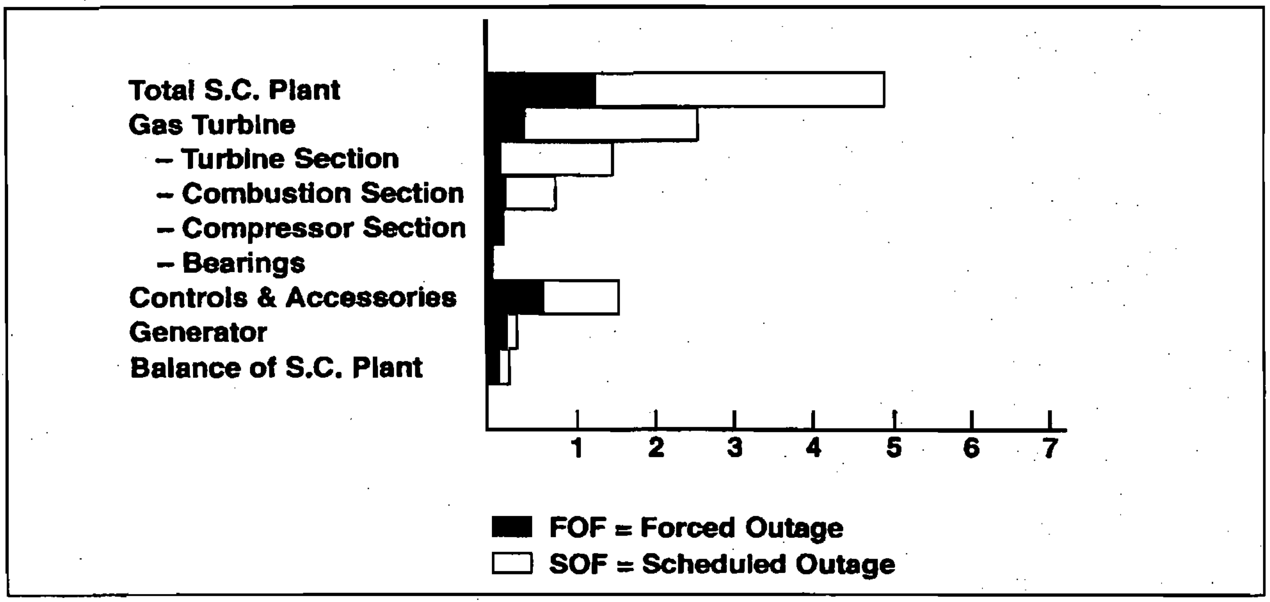

Figure 2: Plant level - top five systems contributions to downtime

nance, safety, reliability or availability of the turbine. The recommendations contained in Technical Information Letters should be reviewed and factored into the overall maintenance planning program.

For a maintenance program to be effective, from both a cost and turbine availability standpoint, owners must develop a general understanding of the relationship between their operating plans and priorities for the plant and the manufacturer's recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting the life and proper operation of his equipment. Each of these issues will be discussed as follows in further detail.

Gas Turbine Design Maintenance Features

The GE heavy-duty gas turbine is designed to withstand severe duty and to be maintained onsite, with off-site repair required only on certain combustion components, hot-gas-path parts and rotor assemblies needing specialized shop service. The following features are designed into GE heavy-duty gas turbines to facilitate on-site maintenance:

- All casings, shells and frames are split on machine horizontal centerline. Upper halves may be lifted individually for access to internal parts.
- With upper-half compressor casings removed, all stator vanes can be slid circumferentially out of the casings for inspection or replacement without rotor removal. On most designs, the variable inlet guide vanes (VIGVs) can be removed radially with upper half of inlet casing removed.
- With the upper-half of the turbine shell lifted, each half of the first stage nozzle assembly can be removed for inspection, repair or replacement without rotor removal. On some units, upper-half, later-stage nozzle assemblies are lifted with the turbine shell, also allowing inspection and/or removal of the turbine buckets.
- All turbine buckets are moment-weighed and computer charted in sets for rotor spool assembly so that they may be replaced without the need to remove or rebalance the rotor assembly.
- All bearing housings and liners are split on the horizontal centerline so that they may be inspected and replaced, when necessary. The lower half of the bearing liner can be removed without removing the rotor.
- All seals and shaft packings are separate from the main bearing housings and casing structures and may be readily removed and replaced.
- Fuel nozzles, combustion liners and flow sleeves can be removed for inspection, maintenance or replacement without lifting any casings.
- All major accessories, including filters and coolers, are separate assemblies that are readily accessible for inspection or maintenance. They may also be individually replaced as necessary.

Inspection aid provisions have been built into GE heavy-duty gas turbines to facilitate conducting several special inspection procedures. These special procedures provide for the visual inspection and clearance measurement of some of the critical internal turbine gas-path components without removal of the gas turbine outer casings and shells. These procedures include gas-path borescope inspection and turbine nozzle axial clearance measurement.

Borescope Inspections

GE heavy-duty gas turbines incorporate provisions in both compressor casings and turbine shells for gas-path visual inspection of intermediate compressor rotor stages, first, second and third-stage turbine buckets and turbine nozzle partitions by means of the optical borescope. These provisions, consisting of radially aligned holes through the compressor casings, turbine shell and internal stationary turbine shrouds, are designed to allow the penetration of an optical borescope into the compressor or turbine flow path area, as shown in *Figure 3.*

An effective borescope inspection program can result in removing casings and shells from a turbine unit only when it is necessary to repair or replace parts. *Figure 4* provides a recommended interval for a planned borescope inspection program following initial base line inspections. It should be recognized that these borescope

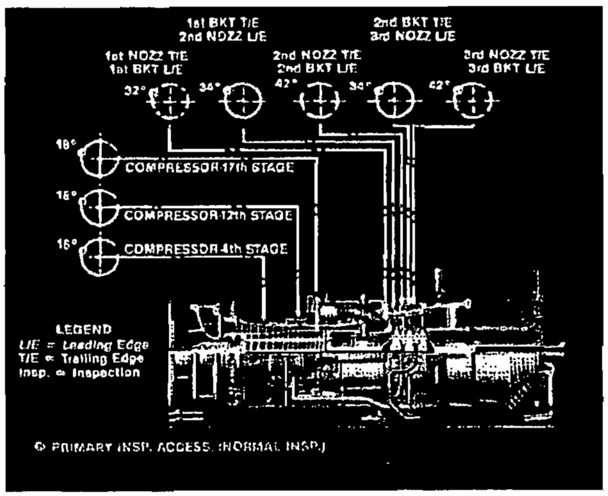

Figure 3: MS7001E gas turbine borescope inspection access locations

Borescope	Gas and Distillate Fuel Oil	At Combustion Inspection or Annually, Whichever Occurs First
	Heavy Fuel Oil	At Combustion Inspection or Semiannually, Whichever Occurs First

Figure 4: Borescope inspection programming

inspection intervals are based on average unit operating modes. Adjustment of these borescope intervals may be made based on operating experience and the individual unit mode of operation, the fuels used and the results of previous borescope inspections.

The application of a monitoring program utilizing a borescope will allow scheduling outages and pre-planning of parts requirements, resulting in lower maintenance costs and higher availability and reliability of the gas turbine.

Major Factors Influencing Maintenance and Equipment Life

There are many factors that can influence equipment life and these must be understood and accounted for in the owner's maintenance planning. As indicated in *Figure 5*, starting cycle, power setting, fuel and level of steam or water injection are key factors in determining the maintenance interval requirements as these factors directly influence the life of critical gas turbine parts.

In the GE approach to maintenance planning, a gas fuel unit operating continuous duty, with no water or steam injection, is established as the baseline condition which sets the maximum recommended maintenance intervals. For operation that differs from the baseline, maintenance factors are established that determine the increased level of maintenance that is required. For example, a maintenance factor of two would indicate a maintenance interval that is half of the baseline interval.

- Cyclic Effects
- Firing Temperature
- Fuel
- Steam/Water Injection

Figure 5: Maintenance cost and equipment life are influenced by key service factors

Starts and Hours Criteria

Gas turbines wear in different ways for different service-duties, as shown in *Figure 6*. Thermal mechanical fatigue is the dominant limiter of life for peaking machines, while creep, oxidation, and corrosion are the dominant limiters of life for continuous duty machines. Interactions of these mechanisms are considered in the GE design criteria, but to a great extent are second order effects. For that reason, GE bases gas turbine maintenance requirements on independent counts of starts and hours. Whichever criteria limit is first reached determines the maintenance interval. A graphical display of the GE approach is shown in *Figure 7*. In this figure, the inspection interval recommendation is defined by the rectangle established by the starts and hours criteria. These recommendations for inspection fall within the design life expectations and are selected such that components verified to be acceptable for continued use at the inspection point will have low risk of failure during the subsequent operating interval.

- Continuous Duty Application
  - Rupture
  - Creep Deflection
  - High-Cycle Fatigue
  - Corrosion
  - Oxidation
  - Erosion
  - Rubs/Wear
  - Foreign Object Damage
- Cyclic Duty Application
  - Thermal Mechanical Fatigue
  - High-Cycle Fatigue
  - Rubs/Wear
  - Foreign Object Damage

Figure 6: Causes of wear - Hot-Gas-Path components

An alternative to the GE approach, which is sometimes employed by other manufacturers, converts each start cycle to an equivalent number of operating hours (EOH) with inspection intervals based on the equivalent hours count. For the reasons stated above, GE does not agree with this approach. This logic can create the impression of longer intervals, while in reality more frequent maintenance inspections are required. Referring again to *Figure 7*, the starts and hours inspection "rectangle" is reduced in half as defined by the diagonal line from the starts limit at the upper left hand corner to the hours limit at the lower right hand corner. Midrange duty applications, with hours per start ratios of 30-50, are particularly penalized by this approach.

This is further illustrated in *Figure 8* for the example of an MS7001EA gas turbine operating on gas fuel, at base load conditions with no steam or water injection or trips from load. The unit operates 4000 hours and 300 starts per year. Following GE's recommendations, the operator would perform the hot gas path inspection after four years of operation, with starts being the limiting condition. Performing maintenance on this same unit based on an equivalent hours criteria would require a hot gas path inspection after 2.4 years. Similarly, for a continuous duty application operating 8000 hours and 160 starts per year, the GE recommendation would be to perform the hot gas

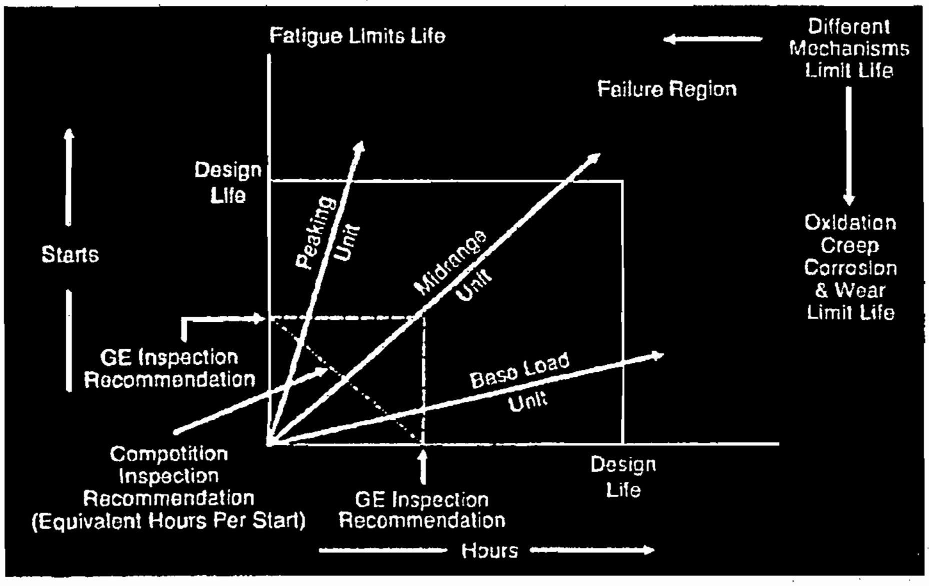

Figure 7: GE bases gas turbine maintenance requirements on independent counts of starts and hours

path inspection after three years of operation with the operating hours being the limiting condition for this case. The equivalent hours criteria would set the hot gas path inspection after 2.1 years of operation for this application.

Service Factors

While GE does not ascribe to the equivalency of starts to hours, there are equivalencies within a wear mechanism that must be considered. As shown in *Figure 9*, influences such as fuel type

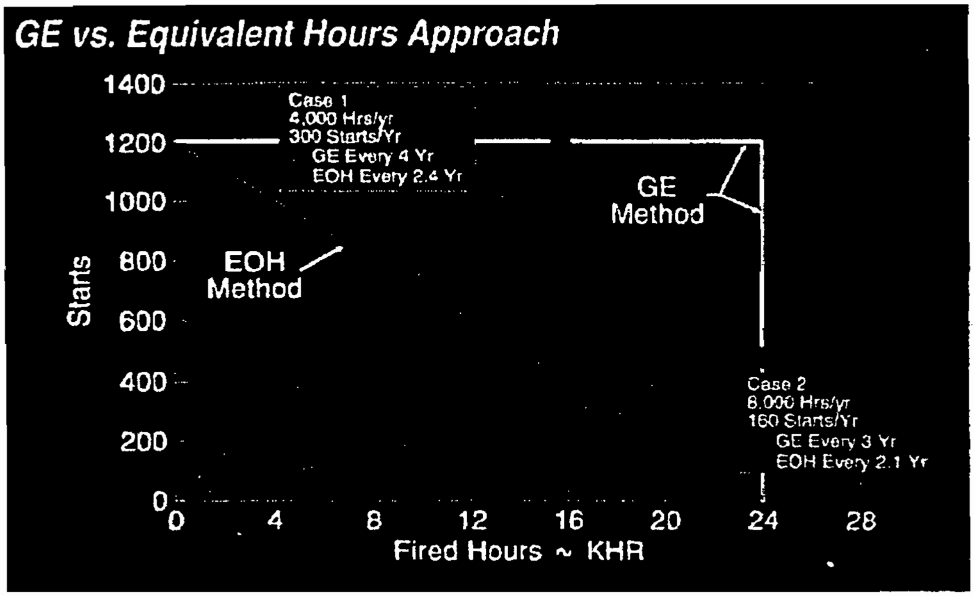

Figure 8: Hot gas path maintenance interval comparisons. GE method vs. EOH method

and quality, firing temperature setting, and the amount of steam or water injection are considered with regard to the hours-based criteria. Start up rate and the number of trips are con-

Typical Max Inspection Intervals (MS6B/MS7EA)

Hot Gas Path Inspection	24,000 hrs or 1200 starts
Major Inspection	48,000 hrs or 2400 starts

Criterion is Hours or Starts (Whichever Occurs First)

Factors Impacting Maintenance

Hours Factors

• Fuel	Gas	1
	Distillate	1.5
	Crude	2 to 3
	Residual	3 to 4
• Peak Load		
• Water/Steam Injection		
	Dry Control	1 (GTD-222)
	Wet Control	1.9 (5% H_2O GTD-222)

Starts Factors

• Trip from Full Load	8
• Fast Load	2
• Emergency Start	20

Figure 9: Maintenance factors - hot-gas-path (buckets and nozzles)

sidered with regard to the starts-based criteria. In both cases, these influences may act to reduce the maintenance intervals. When these service or maintenance factors are involved in a unit's operating profile, the hot-gas-path maintenance "rectangle" that describes the specific maintenance criteria for this operation is reduced from the ideal case, as illustrated in *Figure 10.* The following discussion will take a closer look at the key operating factors and how they can impact maintenance intervals as well as parts refurbishment/replacement intervals.

Fuel

Fuels burned in gas turbines range from clean natural gas to residual oils and impact maintenance, as illustrated in *Figure 11.* Heavier hydrocarbon fuels have a maintenance factor ranging from three to four for residual fuel and two to three for crude oil fuels. These fuels generally release a higher amount of radiant thermal energy, which results in a subsequent reduction

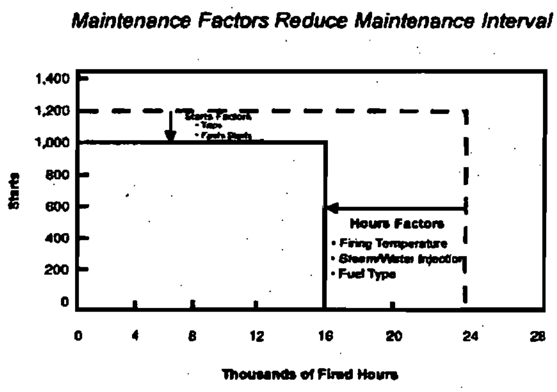

Figure 10. GE maintenance interval for hot-gas inspections

in combustion hardware life, and frequently contain corrosive elements such as sodium, potassium, vanadium and lead that can lead to accelerated hot corrosion of turbine nozzles and buckets. In addition, some elements in these fuels can cause deposits either directly or through compounds formed with inhibitors that are used to prevent corrosion. These deposits impact performance and can lead to a need for more frequent maintenance.

Distillates, as refined, do not generally contain high levels of these corrosive elements, but harmful contaminants can be present in these fuels when delivered to the site. Two common ways of contaminating number two distillate fuel oil are: salt water ballast mixing with the cargo during sea transport, and contamination of the distillate fuel when transported to site in tankers, tank trucks or pipelines that were previously used to transport contaminated fuel, chemicals or leaded gasoline. From *Figure 11*, it can be seen that GE's experience with distillate fuels indicates that the hot gas path maintenance factor can range from as low as one (equivalent to natural gas) to as high as three. Unless operating experience suggests otherwise, it is recommended that a hot gas path

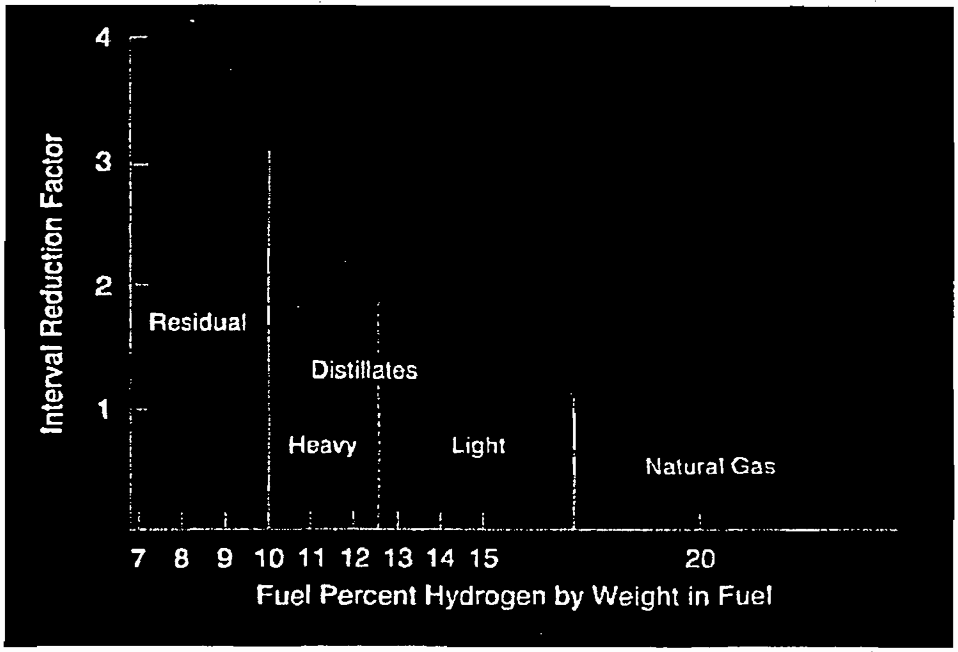

Figure 11: Estimated effect of fuel type on maintenance

maintenance factor of 1.5 be used for operation on distillate oil. Note also that contaminants in liquid fuels can affect the life of gas turbine auxiliary components such as fuel pumps and flow dividers.

As shown in *Figure 11*, gas fuels, which meet GE specifications, are considered the optimum fuel with regard to turbine maintenance and are assigned no negative impact. The importance of proper fuel quality has been amplified with Dry Low NO_x (DLN) combustion systems. Proper adherence to GE fuel specifications in GEI-41040 is required to allow proper combustion system operation, and to maintain applicable warranties. Liquid hydrocarbon carryover can expose the hot-gas-path hardware to severe overtemperature conditions and can result in significant reductions in hot-gas-path parts lives or repair intervals. Owners can control this potential issue by using effective gas scrubber systems and by superheating the gaseous fuel prior to use to provide a nominal 50°F (28°C) of superheat at the turbine gas control valve connection.

The prevention of hot corrosion of the turbine buckets and nozzles is mainly under the control of the owner. Undetected and untreated, a single shipment of contaminated fuel can cause substantial damage to the gas turbine hot gas path components. Potentially high maintenance costs and loss of availability can be minimized or eliminated by:

- Placing a proper fuel specification on the fuel supplier. For liquid fuels, each shipment should include a report that identifies specific gravity, flash point, viscosity, sulfur content, pour point and ash content of the fuel.
- Providing a regular fuel quality sampling and analysis program. As part of this program, an online water in fuel oil monitor is recommended, as is a portable fuel analyzer that, as a

minimum, reads vanadium, lead, sodium, potassium, calcium and magnesium.

- Providing proper maintenance of the fuel treatment system when burning heavier fuel oils and by providing cleanup equipment for distillate fuels when there is a potential for contamination.

In addition to their presence in the fuel, contaminants can also enter the turbine via the inlet air and from the steam or water injected for NO_x emission control or power augmentation. Carryover from evaporative coolers is another source of contaminants. In some cases, these sources of contaminants have been found to cause hot-gas-path degradation equal to that seen with fuel-related contaminants. GE specifications define limits for maximum concentrations of contaminants for fuel, air and steam/water.

Firing Temperatures

Significant operation at peak load, because of the higher operating temperatures, will require more frequent maintenance and replacement of hot-gas-path components. For an MS7001EA turbine, each hour of operation at peak load firing temperature (+100°F/56°C) is the same, from a bucket parts life standpoint, as six hours of operation at base load. This type of operation will result in a maintenance factor of six. *Figure 12* defines the parts life effect corresponding to changes in firing temperature for the MS6001B/MS7001EA/ MS9001E. It should be noted that this is not a linear relationship, as a +200°F/111°C increase in firing temperature would have an equivalency of six times six, or 36:1.

Higher firing temperature reduces hot-gas-path parts lives while lower firing temperature

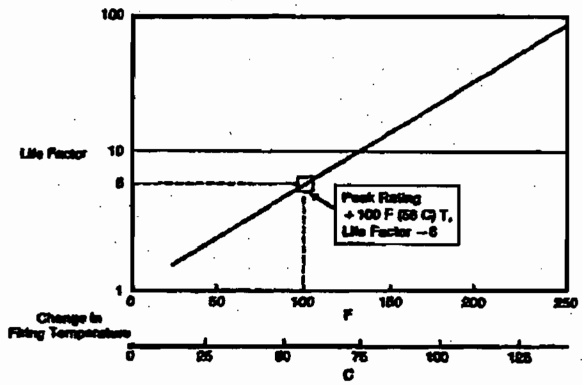

Figure 12. Bucket life firing temperature effect for MS6001B/MS7001EA/MS9001E

increases parts lives. This provides an opportunity to balance the negative effects of peak load operation by periods of operation at part load. However, it is important to recognize that the nonlinear behavior described above will not result in a one for one balance for equal magnitudes of over and under firing operation. Rather, it would take six hours of operation at -100°F/56°C under base conditions to compensate for one hour operation at +100°F/56°C over base load conditions.

It is also important to recognize that a reduction in load does not always mean a reduction in firing temperature. In heat recovery applications, where steam generation drives overall plant efficiency, load is first reduced by reducing fuel and then closing variable inlet guide vanes to reduce inlet airflow while maintaining maximum exhaust temperature. For these combined cycle applications, firing temperature does not decrease until load is reduced below approximately 80% of rated output. Conversely, a turbine running in simple cycle mode maintains full open inlet guide vanes during a load reduction to 80% and will experience over a 200°F/111°C reduction in firing temperature at this output level. The hot-gas-path parts life effects for these different modes of operation are obviously quite different. This turbine control effect is illustrated in *Figure 13.*

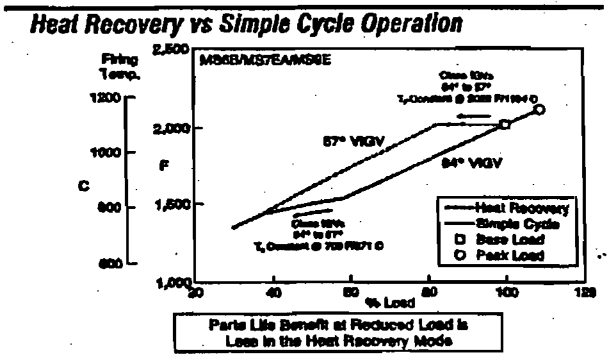

Figure 13. Firing temperature and load relationship - heat recovery vs. simple cycle operation

Firing temperature effects on hot gas path maintenance, as described above, relate to clean burning fuels, such as natural gas and light distillates, where creep rupture of hot gas path components is the primary life limiter and is the mechanism that determines the hot gas path maintenance interval impact. With ash-bearing heavy fuels, corrosion and deposits are the primary influence and a different relationship with firing temperature exists. *Figure 14* illustrates the sensitivity of hot gas path maintenance factor to firing temperature for a heavy fuel operation. It can be seen that while the sensitivity to firing temperature is less, the maintenance factor itself is higher due to issues relating to the corrosive elements contained in these fuels.

Steam/Water Injection

Water (or steam) injection for emissions control or power augmentation can impact parts lives and maintenance intervals even when the water or steam meets GE specifications. This relates to the effect of the added water on the

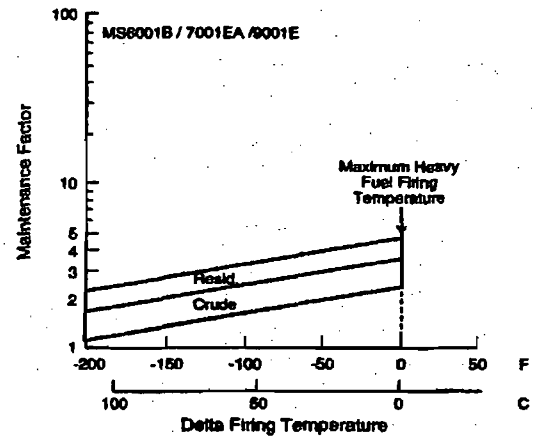

Figure 14. Heavy fuel maintenance factors

hot-gas transport properties. Higher gas conductivity, in particular, increases the heat transfer to the buckets and nozzles and can lead to higher metal temperature and reduced parts lives as shown in *Figure 15.*

Parts life impact from steam or water injection is related to the way the turbine is controlled. The control system on most base load applications reduces firing temperature as water or steam is injected. This counters the effect of the higher heat transfer on the gas side and results in no impact on bucket life. On some installa-

Steam/Water Injection Increases Metal Temperature of Hot-Gas-Path Components

- Water Affects Gas Transport Properties:
  - k - Thermal Conductivity ↑
  - C_p - Specific Heat ↑
  - μ - Viscosity ↔
- This Increases Heat Transfer Coefficients:
- Which Increases Metal Temperature and Decreases Bucket Life

Example (MS7001EA Stage 1 Bucket):
3% Steam (25 ppm NO_x)
H = +4% (Heat Transfer Coefficient)
T_{Metal} = +15 F (8 C)
Life = -33%

For Constant Firing Temperature

Figure 15. Steam water injection and bucket nozzle life

tions, however, the control system is designed to maintain firing temperature constant with water injection level. This results in additional unit output but it decreases parts life as previously described. Units controlled in this way are generally in peaking applications where annual operating hours are low or where operators have determined that reduced parts lives are justified by the power advantage. GE describes these two modes of operation as dry control curve operation and wet control curve operation, respectively. *Figure 16* illustrates the wet and dry control curve and the performance differences that result from these two different modes of control.

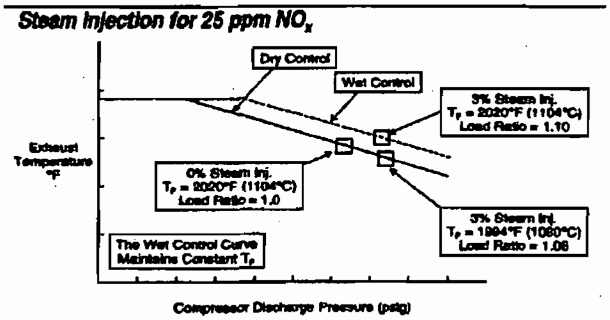

Figure 16. Exhaust temperature control curve - dry vs. wet control MS7001EA

An additional factor associated with water or steam injection relates to the higher aerodynamic loading on the turbine components that results from the injected water increasing the cycle pressure ratio. This additional loading can increase the downstream deflection rate of the second- and third-stage nozzles, which would reduce the repair interval for these components. However, the introduction of GTD-222, a new high creep strength stage two and three nozzle alloy, has minimized this factor.

Maintenance factors relating to water injection for units operating on dry control, range from one, for units equipped with GTD-222 second-stage and third-stage nozzles, to a factor of 1.5 for units equipped with FSX 414 nozzles and injecting 5% water. For wet control curve operation, the maintenance factor is approximately two at 5% water injection for GTD-222 and four for FSX-414.

Cyclic Effects

In the previous discussion, operating factors that impact the hours-based maintenance criteria were described. For the starts-based maintenance criteria, operating factors associated with the cyclic effects produced during startup, operation and shutdown of the turbine must be considered. Operating conditions other than the standard startup and shutdown sequence can potentially reduce the cyclic life of the hot gas path components and rotors, and, if present, will require more frequent maintenance and parts refurbishment and/or replacement.

Hot Gas Path Parts

Figure 17 illustrates the firing temperature changes occurring over a normal startup and shutdown cycle. Light-off, acceleration, loading, unloading and shutdown all produce gas temperature changes that produce corresponding

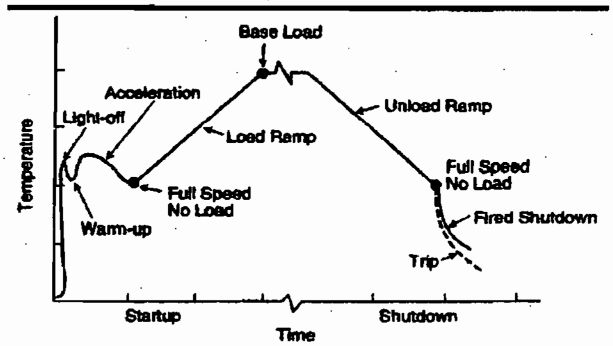

Figure 17. Turbine start/stop cycle - firing temperature changes

metal temperature changes. For rapid changes in gas temperature, the edges of the bucket or nozzle respond more quickly than the thicker bulk section, as pictured in *Figure 18.* These gradients, in turn, produce thermal stresses that,

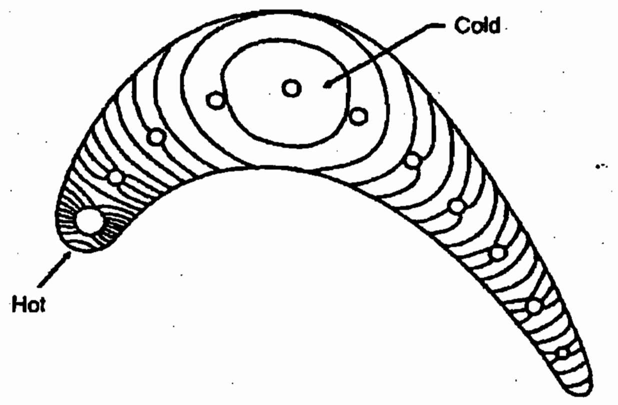

Figure 18. First stage bucket transient temperature distribution

when cycled, can eventually lead to cracking. *Figure 19* describes the temperature strain history of an MS7001EA stage 1 bucket during a normal startup and shutdown cycle. Light-off and acceleration produce transient compressive strains in the bucket as the fast responding leading edge heats up more quickly than the thicker bulk section of the airfoil. At full load conditions, the bucket reaches its maximum metal temperature and a compressive strain produced from the normal steady state temperature gradients that exist in the cooled part. At shutdown, the conditions reverse where the faster responding edges cool more quickly than the bulk section, which results in a tensile strain at the leading edge.

Thermal mechanical fatigue testing has found that the number of cycles that a part can withstand before cracking occurs is strongly influenced by the total strain range and the maximum metal temperature experienced. Any operating condition that significantly increases the strain range and/or the maximum metal temperature over the normal cycle conditions will act to reduce the fatigue life and increase the starts-based maintenance factor. For example, *Figure 20* compares a normal operating cycle with one that includes a trip from full load. The significant increase in the strain range for a trip cycle results in a life effect that equates to eight normal start/stop cycles, as shown. Trips from part load will have a reduced

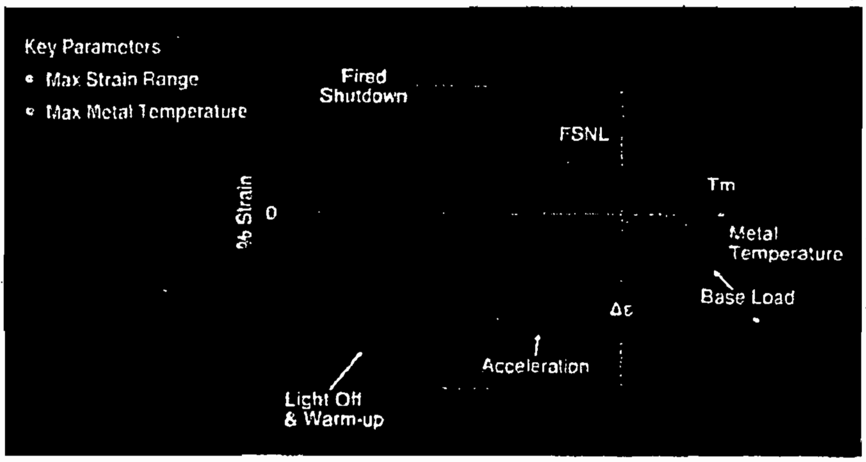

Figure 19. Bucket low cycle fatigue (LCF)

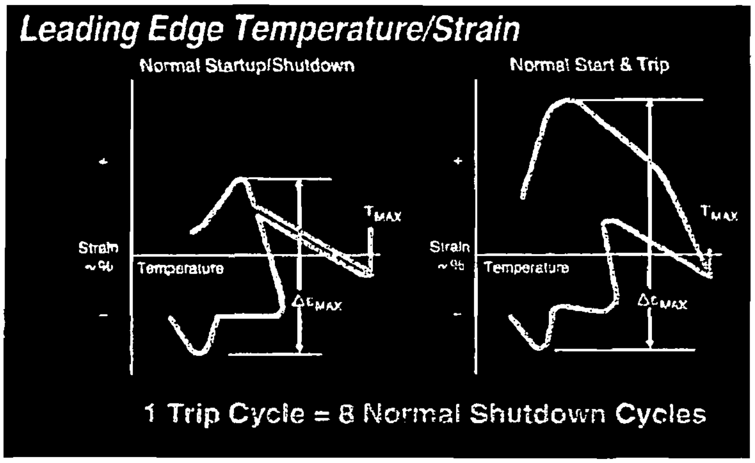

Figure 20. Low cycle fatigue life sensitivities - first stage bucket

impact because of the lower metal temperatures at the initiation of the trip event. *Figure 21* illustrates that while a trip from loads greater than 80% has an 8:1 maintenance factor, a trip from full speed no load would have a maintenance factor of 2:1.

Similarly to trips from load, emergency starts and fast loading will impact the starts-based maintenance interval. This again relates to the increased strain range that is associated with these events. Emergency starts where units are brought from standstill to full load in less than five minutes will have a parts life effect equal to 20 normal start cycles and a normal start with fast loading will produce a maintenance factor of two.

While the factors described above will decrease the starts-based maintenance interval, part load operating cycles would allow for an extension of the maintenance interval. *Figure 22* is a guideline that could be used in considering this type of operation. For example, two operating cycles to maximum load levels of less than 60% would equate to one start to a load greater than 60% or, stated another way, would have a maintenance factor of .5.

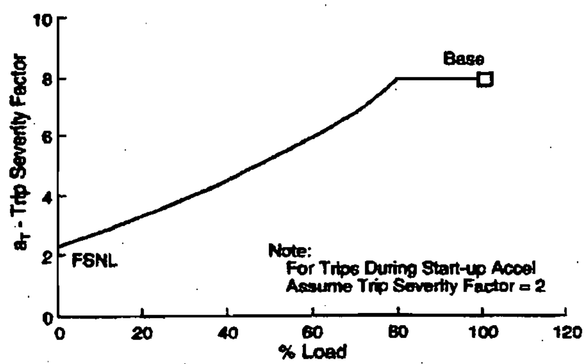

Figure 21. Maintenance factor - trips from load

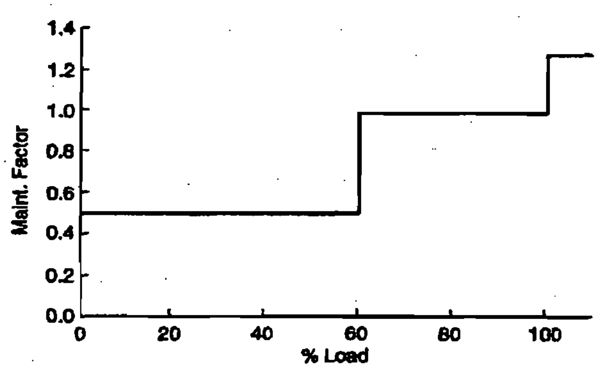

Figure 22. Maintenance factor - effect of start cycle maximum load level

Rotor Parts

In addition to the hot gas path components, the rotor structure maintenance and refurbishment requirements are impacted by the cyclic effects associated with startup, operation and shutdown. Maintenance factors specific to an application's operating profile and rotor design must be determined and incorporated into the operators maintenance planning. Disassembly and inspection of all rotor components is required when the accumulated rotor starts reach the inspection limit. (See *Figure 44* and *Figure 45* in Inspection Internal Section)

For the rotor, the thermal condition when the start-up sequence is initiated is a major factor in determining the rotor maintenance interval and individual rotor component life. Rotors that are cold when the startup commences develop transient thermal stresses as the turbine is brought on line. Large rotors with their longer thermal time constants develop higher thermal stresses than smaller rotors undergoing the same startup time sequence. High thermal stresses will reduce maintenance intervals and thermal mechanical fatigue life.

The steam turbine industry recognized the need to adjust startup times in the 1950 to 1970 time period when power generation market growth led to larger and larger steam turbines operating at higher temperatures. Similar to the steam turbine rotor size increases of the 1950s and 1960s, gas turbine rotors have seen a growth trend in the 1980s and 1990s as the technology has advanced to meet the demand for combined cycle power plants with high power density and thermal efficiency.

With these larger rotors, lessons learned from both the steam turbine experience and the more recent gas turbine experience should be factored into the start-up control for the gas turbine and/or maintenance factors should be determined for an application's duty cycle to quantify the rotor life reductions associated with different severity levels. The maintenance factors so determined are used to adjust the rotor component inspection, repair and replacement intervals that are appropriate to that particular duty cycle.

Though the concept of rotor maintenance factors is applicable to all gas turbine rotors, only MS7001/9001F and FA rotors will be discussed in detail. The rotor maintenance factor for a startup is a function of the downtime following a previous period of operation. As downtime increases, the rotor metal temperature approaches ambient conditions and thermal fatigue impact during a subsequent start-up increases. Since the most limiting location determines the overall rotor impact, the rotor maintenance factor is determined from the upper bound locus of the rotor maintenance factors at these various features. For example, cold starts are assigned a rotor maintenance factor of two and hot starts a rotor maintenance factor of less than one due to the lower thermal stress under hot conditions.

Cold starts are not the only operating factor that influences rotor maintenance intervals and component life. Fast starts and fast loading, where the turbine is ramped quickly to load, increase thermal gradients and are more severe duty for the rotor. Trips from load and particularly trips followed by immediate restarts reduce the rotor maintenance interval as do hot restarts within the first hour of a hot shutdown. *Figure 23* lists recommended operating factors that should be used to determine the rotor's overall maintenance factor for PG7241 and PG9351 design rotors. The factors to be used for other models are determined by applicable Technical Information Letters.

The significance of each of these factors to the maintenance requirements of the rotor is

7241/9351 Design*

	Rotor Maintenance Factors	
	Fast Start	Normal Start
Hot Start Factor** (1-4 Hrs. Down)	1.0	0.6
Warm 1 Start Factor (4-20 Hrs. Down)	1.8	0.9
Warm 2 Start Factor (20-40 Hrs. Down)	2.8	1.4
Cold Start Factor (>40 Hrs. Down)	4.0	2.0
Trip From Load Factor	4.0	4.0
Hot Start Factor (0-1 Hr Down)	4.0	2.0

*Other factors may apply to early 9351 units
**For restarts less than 1 hour after a trip from load, use cold factors

- Factors Are a Function of Machine Thermal Condition at Start-Up
- Trips From Load and Fast Starts Reduce Maintenance Intervals

Figure 23. Operation related maintenance factors

dependent on the type of operation that the unit sees. There are three general categories of operation that are typical of most gas turbine applications. These are peaking, cyclic and continuous duty as described below:

- Peaking units have a relatively high starting frequency and a low number of hours per start. Operation follows a seasonal demand. Peaking units will generally see a high percentage of cold starts.
- Cyclic duty units start daily with only weekend shutdowns. Twelve to sixteen hours per start is typical which results in a warm rotor condition for a large percentage of the starts. Cold starts are generally seen only following a startup after a maintenance outage or following a two day weekend outage.
- Continuous duty applications see a high number of hours per start and most starts are cold because outages are generally maintenance driven. While the percentage of cold starts is high, the total number of starts is low. The rotor maintenance interval on continuous duty units will be determined by service hours rather than starts.

Figure 24 lists operating profiles on the high end of each of these three general categories of gas turbine applications.

As can be seen in *Figure 24*, these duty cycles have different combinations of hot, warm and cold starts with each starting condition having a different impact on rotor maintenance interval as previously discussed. As a result, the starts based rotor maintenance interval will depend on an applications specific duty cycle. In a later section, a method will be described that allows the turbine operator to determine a maintenance factor that is specific to the operation's duty cycle. This maintenance factor uses the rotor maintenance factors described above in combination with the actual duty cycle of a specific application and can be used to determine rotor inspection intervals. In this calculation, the reference duty cycle that yields a starts based maintenance factor equal to one is defined in *Figure 25*. Duty cycles different from the *Figure 25* definition, in particular duty cycles with more cold starts, or a high number of trips, will have a maintenance factor greater than one.

Peaking ~ Cyclic ~ Continuous

	Peaking	Cyclic	Continuous
Hot Start (Down <4 Hr.)	3%	1%	10%
Warm 1 Start (Down 4-20 Hr.)	10%	82%	5%
Warm 2 Start (Down 20-40 Hr.)	37%	13%	5%
Cold Start (Down >40 Hr.)	50%	4%	80%
Hours/Start	4	16	400
Hours/Year	600	4800	8200
Starts per Year	150	300	21
Percent Trips	3%	1%	20%
Number of Trips per Year	5	3	4
Typical Maintenance Factor (Starts Based)	*1.7*	*1.0*	*NA*

- Operational Profile is Application Specific
- Inspection Interval is Application Specific

Figure 24. 7EA gas turbine typical operational profile

Baseline Unit

Cyclic Duty

6	Starts/Week	
16	Hours/Start	
4	Outage/Year Maintenance	
50	Weeks/Year	
4800	Hours/Year	
300	Starts/Year	
0	Trips/Year	
1	Maintenance Factor	
12	Cold Starts/Year (Down >40 Hr.)	4%
39	Warm 2 Starts/Year (Down 20-40 Hr.)	13%
246	Warm 1 Starts/Year (Down 4-20 Hr.)	82%
3	Hot Starts per Year	1%

Baseline Unit Achieves Maintenance Factor = 1

GT25009A.ppt

Figure 25. Baseline for starts based maintenance factor definitions

Air Quality

Maintenance and operating costs are also influenced by the quality of the air that the turbine consumes. In addition to the deleterious effects of airborne contaminants on hot-gas-path components, contaminants such as dust, salt and oil can also cause compressor blade erosion, corrosion and fouling. Twenty-micron particles entering the compressor can cause significant blade erosion. Fouling can be caused by submicron dirt particles entering the compressor as well as from ingestion of oil vapor, smoke, sea salt and industrial vapors.

Corrosion of compressor blading causes pitting of the blade surface, which, in addition to increasing the surface roughness, also serves as potential sites for fatigue crack initiation. These surface roughness and blade contour changes will decrease compressor airflow and efficiency, which in turn reduces the gas turbine output and overall thermal efficiency.

Generally, axial flow compressor deterioration is the major cause of loss in gas turbine output and efficiency. Recoverable losses, attributable to compressor blade fouling, typically account for 70 to 85 of the performance losses seen. As *Figure 26* illustrates, compressor fouling to the extent that airflow is reduced by 5%, will reduce output by 13% and increase heat rate by 5.5% Fortunately, much can be done through proper operation and maintenance procedures to minimize fouling type losses. On-line compressor wash systems are available that are used to maintain compressor efficiency by washing the compressor while at load, before significant fouling has occurred. Off-line systems are used to clean heavily fouled compressors. Other procedures include maintaining the inlet filtration system and inlet evaporative coolers as well as periodic inspection and prompt repair of compressor blading.

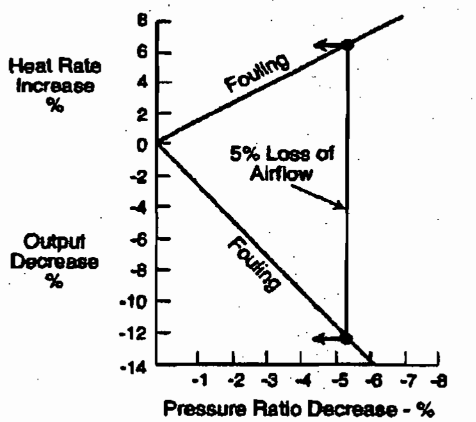

Figure 26. Deterioration of gas turbine performance due to compressor blade fouling

There are also non-recoverable losses. In the compressor, these are typically caused by non-deposit-related blade surface roughness, erosion and blade tip rubs. In the turbine, nozzle throat area changes, bucket tip clearance increases and leakages are potential causes. Some degree of unrecoverable performance degradation should be expected, even on a well-maintained gas turbine.

The owner, by regularly monitoring and recording unit performance parameters, has a very valuable tool for diagnosing possible compressor deterioration.

Maintenance Inspections

Maintenance inspection types may be broadly classified as standby, running and disassembly inspections. The standby inspection is performed during off-peak periods when the unit is not operating and includes routine servicing of accessory systems and device calibration. The running inspection is performed by observing key operating parameters while the turbine is running. The disassembly inspection requires opening the turbine for inspection of internal components and is performed in varying degrees. Disassembly inspections progress from the combustion inspection to the hot-gas-path inspection to the major inspection as shown in *Figure 27*. Details of each of these inspections are described below.

Standby Inspections

Standby inspections are performed on all gas turbines but pertain particularly to gas turbines used in peaking and intermittent-duty service where starting reliability is of primary concern. This inspection includes routinely servicing the battery system, changing filters, checking oil and water levels, cleaning relays and checking device calibrations. Servicing can be performed in offpeak periods without interrupting the availability of the turbine. A periodic startup test run is an essential part of the standby inspection.

The Maintenance and Instructions Manual, as well as the Service Manual Instruction Books, contain information and drawings necessary to perform these periodic checks. Among the most useful drawings in the Service Manual Instruction Books for standby maintenance are the control specifications, piping schematic and electrical elementaries. These drawings provide the calibrations, operating limits, operating characteristics and sequencing of all control devices. This information should be used regularly by operating and maintenance personnel. Careful adherence to minor standby inspection maintenance can have a significant effect on reducing overall maintenance costs and maintaining high turbine reliability. It is essential that a good record be kept of all inspections made and of the maintenance work performed

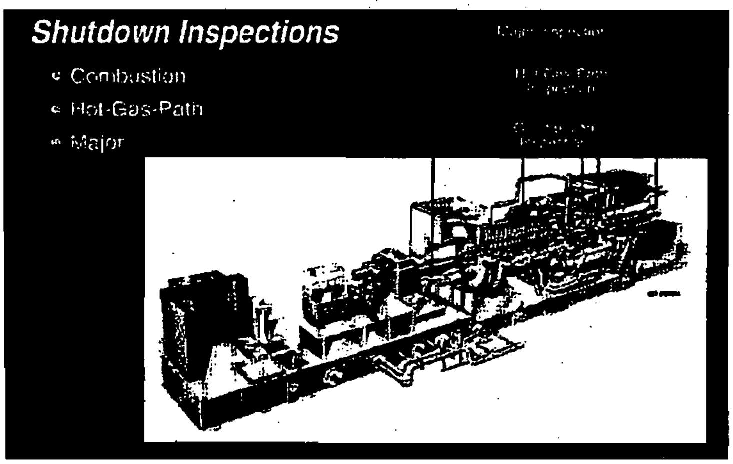

Figure 27. MS7001EA heavy-duty gas turbine - shutdown inspection

in order to ensure establishing a sound maintenance program.

Running Inspections

Running inspections consist of the general and continued observations made while a unit is operating. This starts by establishing baseline operating data during initial startup of a new unit and after any major disassembly work. This baseline then serves as a reference from which subsequent unit deterioration can be measured.

Data should be taken to establish normal equipment start-up parameters as well as key steady state operating parameters. Steady state is defined as conditions at which no more than a 5°F/3°C change in wheelspace temperature occurs over a 15-minute time period.

Data must be taken at regular intervals and should be recorded to permit an evaluation of the turbine performance and maintenance requirements as a function of operating time. This operating inspection data, summarized in *Figure 28*, includes: load versus exhaust temperature, vibration, fuel flow and pressure, lube oil pressure, exhaust gas temperatures, exhaust temperature spread variation and startup time. This list is only a minimum and other parameters should be used as necessary. A graph of these parameters will help provide a basis for judging the conditions of the system. Deviations from the norm help pinpoint impending trouble, changes in calibration or damaged components.

Load vs. Exhaust Temperature

The general relationship between load and exhaust temperature should be observed and compared to previous data. Ambient temperature and barometric pressure will have some effect upon the absolute temperature level. High exhaust temperature can be an indicator of deterioration of internal parts, excessive leaks or a fouled air compressor. For mechanical drive applications, it may also be an indication of increased power required by the driven equipment.

Vibration Level

The vibration signature of the unit should be observed and recorded. Minor changes will occur with changes in operating conditions. However, large changes or a continuously increasing trend give indications of the need to apply corrective action.

- Speed
- Load
- Fired Starts
- Fired Hours
- Site Barometric Reading
- Temperatures
  - Inlet Ambient
  - Compressor Discharge
  - Turbine Exhaust
  - Turbine Wheelspace
  - Lube Oil Header
  - Lube Oil Tank
  - Bearing Drains
  - Exhaust
- Pressures
  - Compressor Discharge
  - Lube Pump(s)
  - Bearing Heading
  - Cooling Water
  - Fuel
  - Filters (Fuel, Lube, Inlet Air)
- Vibration Data for Power Train
- Generator
  - Output Voltage
  - Phase Current
  - VARS
  - Load
  - Field Voltage
  - Field Current
  - Stator Temp.
  - Vibration
- Start-Up Time
- Coast-Down Time

Figure 28. Operating inspection data parameters

Fuel Flow and Pressure

The fuel system should be observed for the general fuel flow versus load relationship. Fuel pressures through the system should be observed. Changes in fuel pressure can indicate the fuel nozzle passages are plugged, or that fuel metering elements are damaged or out of calibration.

Exhaust Temperature and Spread Variation

The most important control function to be observed is the exhaust temperature fuel override system and the back-up over temperature trip system. Routine verification of the operation and calibration of these functions will minimize wear on the hot-gas-path parts.

The variations in turbine exhaust temperature spread should be measured and monitored on a regular basis. Large changes or a continuously increasing trend in exhaust temperature spread indicate combustion system deterioration or fuel distribution problems. If the problem is not corrected, the life of downstream hot-gas-path parts will be reduced.

Start-Up Time

Start-up time is an excellent reference against which subsequent operating parameters can be compared and evaluated. A curve of the starting parameters of speed, fuel signal, exhaust temperature and critical sequence bench marks versus time from the initial start signal will provide a good indication of the condition of the control system. Deviations from normal conditions help pinpoint impending trouble, changes in calibration or damaged components.

Coast-Down Time

Coast-down time is an excellent indicator of bearing alignment and bearing condition. The time period from when the fuel is shut off on a normal shutdown until the rotor comes to a standstill can be compared and evaluated.

Close observation and monitoring of these operating parameters will serve as the basis for effectively planning maintenance work and material requirements needed for subsequent shutdown periods.

Combustion Inspection

The combustion inspection is a relatively short disassembly shutdown inspection of fuel nozzles, liners, transition pieces, crossfire tubes and retainers, spark plug assemblies, flame detectors and combustor flow sleeves. This inspection concentrates on the combustion liners, transition pieces fuel nozzles and end caps which are recognized as being the first to require replacement and repair in a good maintenance program. Proper inspection, maintenance and repair (*Figure 29*) of these items will contribute to a longer life of the downstream parts, such as turbine nozzles and buckets.

Figure 27 illustrates the section of an MS7001EA unit that is disassembled for a combustion inspection. The combustion liners, transition pieces and fuel nozzle assemblies should be removed and replaced with new or repaired components to minimize downtime. The removed liners, transition pieces and fuel nozzles can then be cleaned and repaired after the

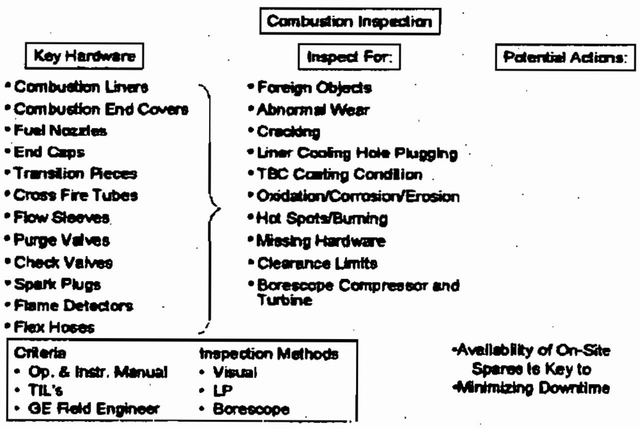

Figure 29. Combustion inspection - key elements

unit is returned to operation and be available for the next combustion inspection interval. Typical combustion inspection requirements for MS6001B/7001EA/9001E machines are:

- Inspect and identify combustion chamber components.
- Inspect and identify each crossfire tube, retainer and combustion liner.
- Inspect combustion chamber interior for debris and foreign objects.
- Inspect flow sleeve welds for cracking. Inspect transition piece for wear and cracks.
- Inspect fuel nozzles for plugging at tips, erosion of tip holes and safety lock of tips.
- Inspect all fluid, air, and gas passages in nozzle assembly for plugging, erosion, burning, etc.
- Inspect spark plug assembly for freedom from binding, check condition of electrodes and insulators.
- Replace all consumables and normal wear-and-tear items such as seals, lockplates, nuts, bolts, gaskets, etc.
- Perform visual inspection of first-stage turbine nozzle partitions and borescope inspect (*Figure 3*) turbine buckets to mark the progress of wear and deterioration of these parts. This inspection will help establish the schedule for the hot-gas-path inspection.
- Perform borescope inspection of compressor.
- Enter the combustion wrapper and observe the condition of blading in the aft end of axial-flow compressor with a borescope.
- Visually inspect the compressor inlet and turbine exhaust areas, checking condition of IGVs, IGV bushings, last-stage buckets and exhaust system components.
- Verify proper operation of purge and check valves. Confirm proper setting and calibration of the combustion controls.

After the combustion inspection is complete and the unit is returned to service, the removed combustion liners and transition pieces can be bench inspected and repaired, if necessary, by either competent on-site personnel, or off-site at a qualified GE Combustion Service Center. The removed fuel nozzles can be cleaned on-site and flow tested on-site, if suitable test facilities are available. For F Class gas turbines it is recommended that repairs and fuel nozzle flow testing be performed at qualified GE Service Centers.

Hot-Gas-Path Inspection

The purpose of a hot-gas-path inspection is to examine those parts exposed to high temperatures from the hot gases discharged from the combustion process. The hot-gas-path inspection outlined in *Figure 30* includes the full scope of the combustion inspection and, in addition, a detailed inspection of the turbine nozzles, stationary stator shrouds and turbine buckets. To perform this inspection, the top half of the turbine shell must be removed. Prior to shell removal, proper machine centerline support using mechanical jacks is necessary to assure proper alignment of rotor to stator, obtain accurate half-shell clearances and prevent twisting of the stator casings. The MS7001EA jacking procedure is illustrated in *Figure 31*.

For inspection of the hot-gas-path (*Figure 27*), all combustion transition pieces and the first-

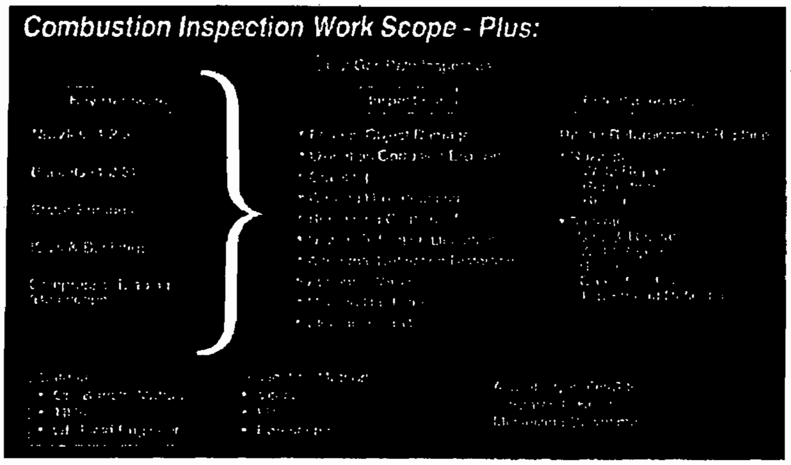

Figure 30. Hot-gas-path inspection - key elements

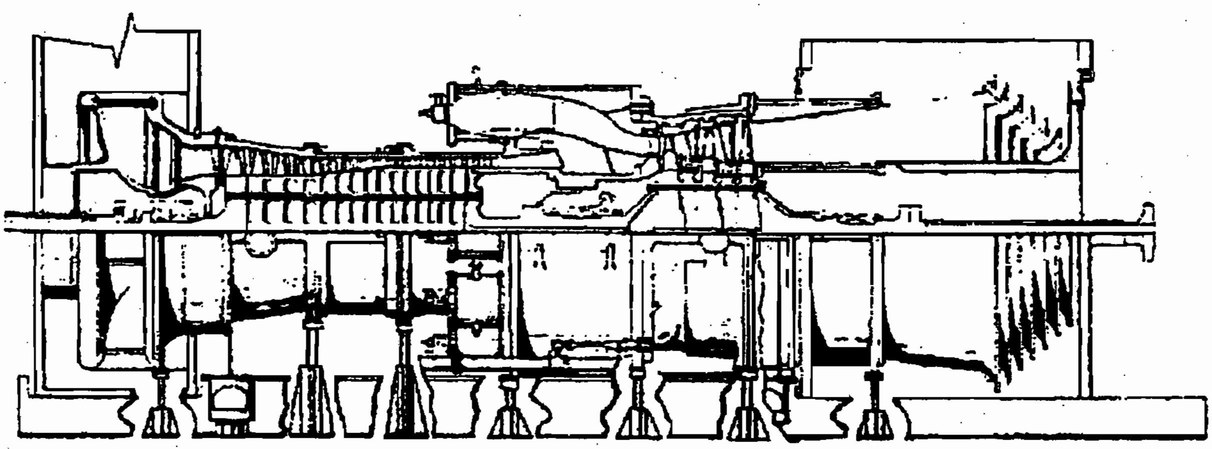

Figure 31. Stator tube jacking procedure - MS7001EA

stage turbine nozzle assemblies must be removed. Removal of the second- and third-stage turbine nozzle segment assemblies is optional, depending upon the results of visual observations and clearance measurement. The buckets can usually be inspected in place. Also, it is usually worthwhile to fluorescent penetrant inspect (FPI) the bucket vane sections to detect any cracks. In addition, a complete set of internal turbine radial and axial clearances (opening and closing) must be taken during any hot-gas-path inspection. Typical hot gas-path inspection requirements for all machines are:

- Inspect and record condition of first-, second- and third-stage buckets. If it is determined that the turbine buckets should be removed, follow bucket removal and condition recording instructions. The first-stage bucket protective coating should be evaluated for remaining coating life.
- Inspect and record condition of first-, second- and third-stage nozzles.
- Inspect and record condition of later-stage nozzle diaphragm packings.

Check seals for rubs and deterioration of clearance.

- Record the bucket tip clearances. Inspect bucket shank seals for clearance, rubs and deterioration.
- Check the turbine stationary shrouds for clearance, cracking, erosion, oxidation, rubbing and build-up.
- Check and replace any faulty wheelspace thermocouples.
- Enter compressor inlet plenum and observe the condition of the forward section of the compressor. Pay specific attention to IGVs, looking for corrosion, bushing wear evidenced by excessive clearance and vane cracking.
- Enter the combustion wrapper and, with a borescope, observe the condition of the blading in the aft end of the axial flow compressor.
- Visually inspect the turbine exhaust area for any signs of cracking or deterioration.

The first-stage turbine nozzle assembly is exposed to the direct hot-gas discharge from the combustion process and is subjected to the highest gas temperatures in the turbine section. Such conditions frequently cause nozzle cracking and oxidation and, in fact, this is expected. The second- and third-stage nozzles are exposed to high gas bending loads which, in combination with the operating temperatures, can lead to downstream deflection and closure of critical axial clearances. To a degree, nozzle distress can be tolerated and criteria have been established for determining when repair is required. These limits are contained in the Maintenance and Instruction Books previously described. However, as a general rule, first stage nozzles will require repair at the hot-gas path inspection. The second- and third-stage nozzles may require refurbishment to re-establish the proper axial clearances. Normally, turbine nozzles can be repaired several times to extend life and it is generally repair cost versus replacement cost that dictates the replacement decision.

Coatings play a critical role in protecting the first stage buckets to ensure that the full capability of the high strength superalloy is maintained and that the bucket rupture life meets design expectations. This is particularly true of cooled bucket designs that operate above 1985°F (1085°C) firing temperature. Significant exposure of the base metal to the environment will accelerate the creep rate and can lead to premature replacement through a combination of increased temperature and stress and a reduction in material strength, as described in *Figure 32*. This degradation process is driven by oxidation of the unprotected base alloy. In the past, on early generation uncooled designs, surface degradation due to corrosion or oxidation was considered to be a performance issue and not a factor in bucket life. This is no longer the case at the higher firing temperatures of current generation designs.

Given the importance of coatings, it must be recognized that even the best coatings available will have a finite life and the condition of the coating will play a major role in determining bucket replacement life. Refurbishment through stripping and recoating is an option for extending bucket life, but if recoating is selected, it should be done before the coating has breached to expose base metal. Normally, for turbines in the MS7001EA class, this means that recoating will be required at the hot-gas-path inspection. If recoating is not performed at the hot-gas-path inspection, the runout life of the buckets would generally extend to the

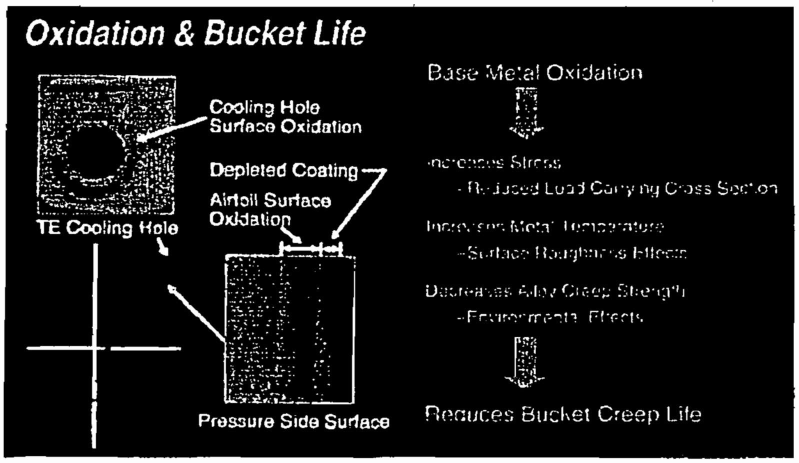

Figure 32. Stage 1 bucket oxidation and bucket life

major inspection, at which point the buckets would be replaced. For F class gas turbines recoating of the first stage buckets is recommended at each hot gas path inspection.

Recoating is not considered an option for buckets with uncoated cooling holes. The economics of recoating buckets must look at the cost to recoat versus the cost to replace buckets at more frequent intervals. Economic evaluations of this tradeoff suggest that recoating may make sense for the larger designs but less so for the smaller frame sizes.

Visual and borescope examination of the hot gas-path parts during the combustion inspections as well as nozzle-deflection measurements will allow the operator to monitor distress patterns and progression. This makes part-life predictions more accurate and allows adequate time to plan for replacement or refurbishment at the time of the hot-gas-path inspection. It is important to recognize that to avoid extending the hot-gas-path inspection, the necessary spare parts should be on site prior to taking the unit out of service.

Major Inspection

The purpose of the major inspection is to examine all of the internal rotating and stationary components from the inlet of the machine through the exhaust section of the machine. A major inspection should be scheduled in accordance with the recommendations in the owner's Maintenance and Instructions Manual or as modified by the results of previous borescope and hot-gas-path inspection. The work scope shown in *Figure 33* involves inspection of all of the major flange-to-flange components of the gas turbine which are subject to deterioration during normal turbine operation. This inspection includes previous elements of the combustion and hot-gas-path inspections, in addition to laying open the complete flange-to-flange gas turbine to the horizontal joints, as shown in *Figure 34*, with inspections being performed on individual items.

Prior to removing casings, shells and frames, the unit must be properly supported. Proper centerline support using mechanical jacks and jacking sequence procedures are necessary to assure proper alignment of rotor to stator, obtain accurate half shell clearances and to prevent twisting of the casings while on the half shell.

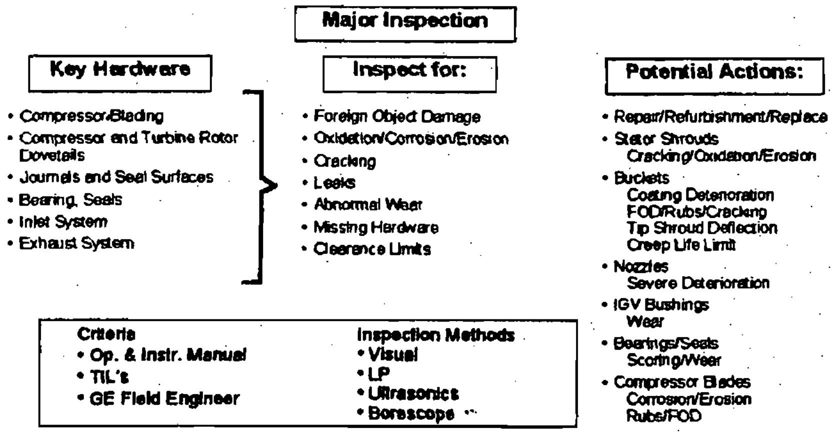

Figure 33. Gas turbine major inspection - key elements

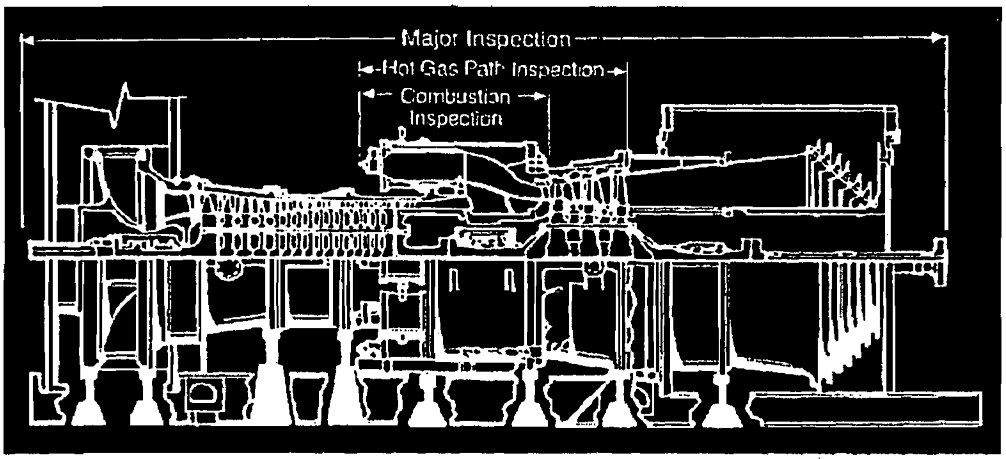

Figure 34. Major inspection work scope

Typical major inspection requirements for all machines are:

- All radial and axial clearances are checked against their original values (opening and closing).
- Casings, shells and frames/ diffusers are inspected for cracks and erosion.
- Compressor inlet and compressor flow-path are inspected for fouling, erosion, corrosion and leakage. The IGVs are inspected, looking for corrosion, bushing wear and vane cracking.
- Rotor and stator compressor blades are checked for tip clearance, rubs, impact damage, corrosion pitting, bowing and cracking.
- Turbine stationary shrouds are checked for clearance, erosion, rubbing, cracking, and build-up.
- Seals and hook fits of turbine nozzles and diaphragms are inspected for rubs, erosion, fretting or thermal deterioration.

- Turbine buckets are removed and a non-destructive check of buckets and wheel dovetails is performed (first stage bucket protective coating should be evaluated for remaining coating life). First-stage buckets that were not recoated at the hot-gas-path inspection should be replaced.
- Rotor inspections recommended in the maintenance and inspection manual or by Technical Information Letters should be performed.
- Bearing liners and seals are inspected for clearance and wear.
- Inlet systems are inspected for corrosion, cracked silencers and loose parts.
- Exhaust systems are inspected for cracks, broken silencer panels or insulation panels.
- Check alignment - gas turbine to generator/gas turbine to accessory gear.

Comprehensive inspection and maintenance guidelines have been developed by GE and are provided in the Maintenance and Instructions Manual to assist users in performing each of the inspections previously described.

Parts Planning

Lack of adequate on-site spares can have a major effect on plant availability; therefore, prior to a scheduled disassembly type of inspection, adequate spares should be on site. A planned outage such as a combustion inspection, which should only take two to five days, could take weeks. GE will provide recommendations regarding the types and quantities of spare parts needed; however, it is up to the owner to purchase these spare parts on a planned basis allowing adequate lead times.

Early identification of spare parts requirements ensures their availability at the time the planned inspections are performed. There are two documents which support the ordering of gas turbine parts by catalog number. The first is the Renewal Parts Catalog - Illustrations and Text. This document contains generic illustrations which are used for identifying parts. The second document, the Renewal Parts Catalog Ordering Data Manual, contains unit site-specific catalog ordering data.

Additional benefits available from the renewal parts catalog data system are the capability to prepare recommended spare parts lists for the combustion, hot-gas-path and major inspections as well as capital and operational spares.

Furthermore, interchangeability lists may be prepared for multiple units. The information contained in the Catalog Ordering Data Manual can be provided as a computer printout, on microfiche or on a computer disc. As the size of the database grows, and as generic illustrations are added, the usefulness of this tool will be continuously enhanced.

Typical expectations for estimated repair cycles for some of the major components are shown in *Figure 35.* Many engineering judgments are built into this table, including base-load continuous duty on natural-gas fuel and operation of the unit in accordance with all of the manufacturer's specifications and instructions. Maintenance inspections and repairs are also assumed to be done in accordance with the manufacturer's specifications and instructions. The actual repair and replacement cycles for any particular gas turbine should be based on the user's operating procedures, experience, maintenance practices and repair practices. The maintenance factors previously described can have a major impact on both the compo-

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Transition Pieces	CI	6 (CI)	6 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Cross-Fire Tubes	CI	3 (CI)	3 (CI)
Flow Divider (Distillate)	CI	3 (CI)	3 (CI)
Fuel Pump (Distillate)	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Buckets	HGPI *	2 (HGPI)/3 (HGPI) **	3 (HGPI)
Stage 2 Buckets	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Buckets	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 & 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)

Operation/Maintenance/Repair In Accordance With GE Specifications and Instructions Is Key to Minimizing Repair and Replacement Costs.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
* When Recoating, Perform After One Hours-Based Hot Gas Path Interval
** 2 Hot Gas Path Intervals Without Recoat, 3 Hot Gas Path Intervals With Recoat

Figure 35. Estimated repair and replacement cycles (MS6001B/MS7001EA/MS9001E)

nent repair interval and service life. For this reason, the intervals given in *Figure 35* should only be used as guidelines and not certainties for long range parts planning. Owners may want to include contingencies in their parts planning.

Figures 37–40 show expected repair and replacement cycles for MS6001FA, MS7001F/ FA and MS9001F/FA machines. These values reflect current production hardware. To achieve these lives, current production parts with design improvements and newer coatings are required. With earlier production hardware, some of these lives may not be achieved. Operating factors and experience gained during the course of recommended inspection and maintenance procedures will be a more accurate predictor of the actual intervals.

It should be recognized that, in some cases, the service life of a component is reached when it is no longer economical to repair any deterioration as opposed to replacing at a fixed interval. This is illustrated in *Figure 36* for a first stage nozzle, where repairs continue until either the nozzle cannot be restored to minimum acceptance standards or the repair cost exceeds or approaches the replacement cost. In other cases, such as first-stage buckets, repair options are limited by factors such as irreversible material damage. In both cases, users should follow GE recommendations regarding replacement or repair of these components.

While the parts lives for *Figure 35* and *Figures 37–40* are guidelines, the life consumption of individual parts within a parts set can have variations. The repair versus replacement economics shown in *Figure 36* may lead to a certain percentage of "fallout", or scrap, of parts being repaired. Those parts that fallout during the

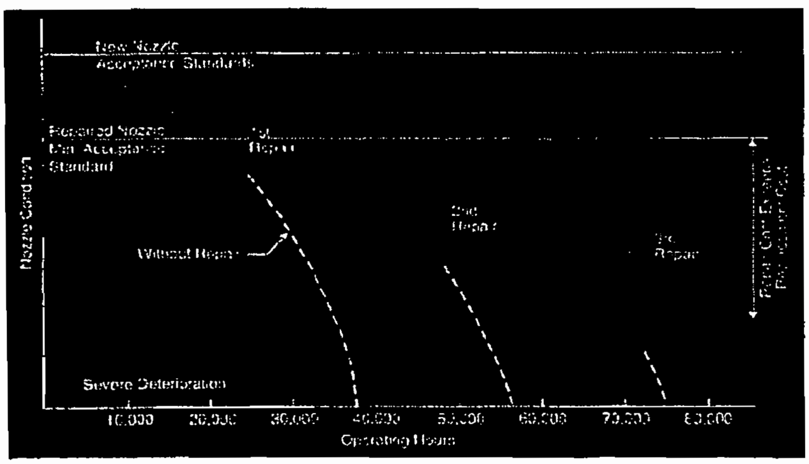

Figure 36. First-stage nozzle wear-preventive maintenance gas fired - continuous dry - base load

PG6101(FA) / PG7191(F) / PG7221(FA) / PG9301(F) / PG9311(FA) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)(1)	5 (CI)
Caps	CI	5 (CI)(1)	5 (CI)
Transition Pieces	CI	5 (CI)(1)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)(2)	2 (HGPI)(2)
Stage 2 Shrouds	HGPI	2 (HGPI)(2)	2 (HGPI)(2)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	2 (HGPI) / 3 (HGPI)(3)	2 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(4)	3 (HGPI)(4)
Stage 3 Bucket	HGPI	3 (HGPI)(4)	3 (HGPI)(4)

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) Current hardware may not achieve this interval.
(2) The goal is to increase to 3 (HGPI). Decision will be made based on fleet leader experience.
(3) Requires 7FA+ parts or 7FA parts with GT33 INPLUS™ coating and other design improvements. Also requires a repair and recoat at every HGPI.
(4) With welded hardface on shroud. Recoating at 1st HGPI is required to achieve 3 HGPI replacement life.

Figure 37. Estimated repair and replacement cycles

PG7231FA Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)(1)	5 (CI)
Caps	CI	5 (CI)(1)	5 (CI)
Transition Pieces	CI	5 (CI)(1)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)(2)	2 (HGPI)(2)
Stage 2 Nozzles	HGPI	2 (HGPI)(2)	2 (HGPI)(2)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)(2)	2 (HGPI)(2)
Stage 2 Shrouds	HGPI	2 (HGPI)(2)	2 (HGPI)(2)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	3 (HGPI)(2)	2 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(3)	3 (HGPI)(3)
Stage 3 Bucket	HGPI	2 (HGPI)	3 (HGPI)

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) Current hardware may not achieve this interval.
(2) The goal is to increase to 3 (HGPI). Decision will be made based on fleet leader experience. Also requires a repair and recoat at every HGPI.
(3) Recoating at 1st HGPI is required to achieve 3 HGPI replacement life

Figure 38. Estimated repair and replacement cycles

PG7241FA Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 2 Nozzles	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 2 Shrouds	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	3 (HGPI)(1)	2 (HGPI)
Stage 2 Bucket	HGPI	2 (HGPI)	3 (HGPI)(2)
Stage 3 Bucket	HGPI	1 (HGPI)	3 (HGPI)

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) The goal is to increase to 3 (HGPI). Decision will be made based on fleet leader experience. Also requires a repair and recoat at every HGPI
(2) Recoating at 1st HGPI is required to achieve 3 HGPI replacement life.

Figure 39. Estimated repair and replacement cycles

PG9351FA Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 2 Nozzles	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 2 Shrouds	HGPI	2 (HGPI)(1)	2 (HGPI)(1)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	3 (HGPI)(1)	2 (HGPI)
Stage 2 Bucket	HGPI	1 (HGPI)	3 (HGPI)(2)
Stage 3 Bucket	HGPI	1 (HGPI)	3 (HGPI)

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) The goal is to increase to 3 (HGPI). Decision will be made based on fleet leader experience
Also requires a repair and recoat at every HGPI
(2) Recoating at 1st HGPI is required to achieve 3 HGPI replacement life.

Figure 40. Estimated repair and replacement cycles

repair process will need to be replaced by new parts. The amount of fallout of parts depends on the unit operating environment history, the specific part design, and the current state-of-the-art for repair technology.

Inspection Intervals

Figure 41 lists the recommended combustion, hot-gas-path and major inspection intervals for current production GE turbines operating under ideal conditions of gas fuel, base load, no water or steam injection, and without a Dry Low NO_X combustor. Considering the maintenance factors discussed previously, an adjustment from these maximum intervals may be necessary, based on the specific operating conditions of a given application. Initially, this determination is based on the expected operation of a turbine installation, but this should be reviewed and adjusted as actual operating and maintenance data are accumulated. While reductions in the maximum intervals will result from the factors described previously, increases in the maximum interval can also be considered

Type of Inspection	Hours/Starts				
	MS32/51/52 Uprates	MS6B	MS7E/EA	9E	MS6F/7F/9F
Combustion	12,000/800	12,000/1,200	8,000/800	8,000/800	8,000/400
Hot Gas Path	Eliminated/1,200	24,000/1,200	24,000/1,200	24,000/900	24,000/900
Major	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400

Factors That Can Reduce Maintenance Intervals

- Fuel
- Load Setting
- Steam/Water Injection
- Peak Load T_F Operation
- Trips From Load
- Start Cycle
- HGP Hardware Design

Figure 41. Base line recommended inspection intervals: base load - gas fuel - dry

where operating experience has been favorable. The condition of the hot-gas-path parts provides a good basis for customizing a program of inspection and maintenance.

GE can assist operators in determining the appropriate maintenance intervals for their particular application. Equations have been developed that account for the factors described earlier and can be used to determine application specific hot-gas-path and major inspection intervals. The hours-based hot-gas-path criterion is determined from the equation given in *Figure 42*. With this equation, a maintenance factor is determined that is the ratio of factored operating hours and actual operating hours. The factored hours consider the specifics of the duty cycle relating to fuel type, load setting and steam or water injection. Maintenance factors greater than one reduce the hot gas path inspection interval from the 24,000 hour ideal case for continuous base load, gas fuel and no steam or water injection. To determine the application specific maintenance interval, the maintenance factor is divided into 24,000, as shown in *Figure 42*.

The starts-based hot-gas-path criterion is determined from the equation given in *Figure 43*. As with the hours-based criteria, an application specific starts-based hot gas path inspection interval is calculated from a maintenance factor that is determined from the number of trips typically being experienced, the load level and loading rate.

$$\text{Maintenance Interval (Hours)} = \frac{24000}{\text{Maintenance Factor}}$$

Where:

$$\text{Maintenance Factor} = \frac{\text{Factored Hours}}{\text{Actual Hours}}$$

Factored Hours = $(K + M \times I) \times (G + 1.5D + A_f H + 6P)$

Actual Hours = $(G + D + H + P)$

G = Annual Base Load Operating Hours on Gas Fuel
D = Annual Base Load Operating Hours on Distillate Fuel
H = Annual Operating Hours on Heavy Fuel
A_f = Heavy Fuel Severity Factor (Residual A_f = 3 to 4, Crude A_f = 2 to 3)
P = Annual Peak Load Operating Hours
I = Percent Water/Steam Injection Referenced to Inlet Air Flow
M & K = Water/Steam Injection Constants

M	K	Control	Steam Injection	N2/N3 Material
0	1	Dry	<2.2%	GTD-222/FSX-414
0	1	Dry	>2.2%	GTD-222
.18	.6	Dry	>2.2%	FSX-414
.18	1	Wet	>0%	GTD-222
.55	1	Wet	>0%	FSX-414

Figure 42. Hot gas path inspection: hours-based criterion

The starts-based rotor maintenance interval is determined from the equation given in *Figure 44*. Adjustments to the rotor maintenance interval are determined from rotor-based operating factors as were described previously. In the cal-

MS6001/7001/9001

$$\text{Maintenance Interval (Starts)} = \frac{S}{\text{Maintenance Factor}}$$

Where:

$$\text{Maintenance Factor} = \frac{\text{Factored Starts}}{\text{Actual Starts}}$$

Factored Starts = $(0.5\,NA + NB + 1.3NP + 20E + 2F + \sum_{i=1}^{n} a_{Ti} T_i)$

Actual Starts = $(NA + NB + NP + E + F + T)$

Actual Starts = $(NA + NB + NP + E + F + T)$

S = Maximum Starts-Based Maintenance Interval (Model Size Dependent)
NA = Annual Number of Part Load Start/Stop Cycles (<60% Load)
NB = Annual Number of Normal Base Load Start/Stop Cycles
NP = Annual Number of Peak Load Start/Stop Cycles
E = Annual Number of Emergency Starts
F = Annual Number of Fast Load Starts
T = Annual Number of Trips
a_T = Trip Severity Factor = f (Load) (See Figure 21)
n = Number of Trip Categories (i.e., Full Load, Part Load, etc.)

Model Series	S	Model Series	S
MS6B/MS7EA	1,200	MS9E	900
MS6FA	1,200	MS7F/7FA/9F/9FA	900

Figure 43. Hot gas path inspection starts-based condition

Starts Based Rotor Life Calculation

$$\text{Maintenance Factor} = \frac{(Fh*Nh + Fw1*Nw1 + Fw2*Nw2 + Fc*Nc + Ft*Nt)}{(Nh + Nw1 + Nw2 + Nc)}$$

$$\text{Rotor Maintenance Interval} = \frac{5000}{\text{Maintenance Factor}} \quad \text{(Not to exceed 5000 starts)} \quad MF>=1$$

Where:	Fast	Normal
Fh – Hot start factor (Down 1-4 hr)	1.0	0.5
Fw1 – Warm1 start factor (Down 4-20 hr)	1.8	0.9
Fw2 – Warm2 start factor (Down 20-40 hr)	2.8	1.4
Fc – Cold start factor (Down >40hr)	4.0	2.0
Ft – Trip from load factor	4.0	4.0
	PG7241 & PG9351 Designs*	

* For restarts within the first hour after a hot shutdown use cold start rotor life factor

Nh – Number of Hot Starts
Nw1 – Number of Warm1 starts
NW2 – Number of Warm2 Starts
Nc – Number of Cold starts
Nt – Number of trips

Figure 44. Rotor maintenance factor for starts-based criterion

culation for the starts-based rotor maintenance interval, equivalent starts are determined for cold, warm, and hot starts over a defined time period by multiplying the appropriate cold, warm and hot start operating factor times and number of cold, warm and hot starts respectively. In this calculation, the type of start must be considered. Additionally, equivalent starts for trips from load are added. The equivalent start total is divided by the actual number of starts to yield the maintenance factor. The rotor starts based maintenance interval for a specific application is determined by dividing the baseline rotor maintenance interval of 5000 starts by the calculated maintenance factor. As indicated in *Figure 44,* the rotor maximum maintenance interval is 5000 starts. Calculated maintenance factors that are less than one are not considered.

Figure 45 describes the procedure to determine the hours-based maintenance criterion. Peak load operation is the primary maintenance factor for the Frame MS7001/9001F and FA class rotors and will act to increase the hours-based maintenance factor and to reduce the rotor maintenance interval. Hours on turning gear are also considered as an equivalent hours adder as noted in *Figure 45.*

For rotors other than Frame MS7001/9001F and FA, rotor maintenance should be performed at intervals recommended by GE through issued Technical Information Letters. Where no recommendations have been made, rotor inspection should be performed at 5,000 starts or 200,000 hours.

As previously described, the hours and starts operating spectrum for the application is evaluated against the recommended hot gas path intervals for starts and for hours. The limiting

Hours Based Rotor Life Calculation

$$\text{Maintenance Factor} = \frac{H + 2*P + 2*TG}{H + P}$$

$$\text{Rotor Maintenance Interval} = \frac{144000}{\text{Maintenance Factor}}$$

Where:

H – Base load hours
P – Peak load hours
TG – Hours on turning gear

Figure 45. Rotor maintenance factor for hours based criterion

criterion (hours or starts) determines the maintenance interval. An example of the use of these equations is contained in the appendix.

While the hot-gas-path and major inspection interval can be determined from the equations given in *Figures 42–45*, the combustion intervals have not been reduced to that form. Recommendations are provided that are specific to the combustion hardware design, fuel, type of diluent and emissions level. Recommendations for combustion intervals for specific application can be provided by the GE Energy Services representative.

As an example, *Figure 46* describes the recommended combustion inspection intervals for the MS7001EA. As noted, application of the new Extendor™ Combustion System Wear Kit has the potential to significantly increase the stated intervals.

Manpower Planning

It is essential that advanced manpower planning be conducted prior to an outage. It should be understood that a wide range of experience, productivity and working conditions exist around the world. However, based upon maintenance inspection man-hour assumptions, such as the use of an average crew of workers in the United States with trade skill (but not necessarily direct gas turbine experience), with all needed tools and replacement parts (no repair time) available, an estimate can be made. These estimated craft labor man-hours should include controls and accessories and the generator. In addition to the craft labor, additional resources are needed for technical direction of the craft labor force, specialized tooling, engineering reports, and site mobilization/de-mobilization.

Inspection frequencies and the amount of downtime varies within the gas turbine fleet due to different duty cycles and the economic need for a unit to be in a state of operational readiness. It can be demonstrated that an 8000-hour interval for a combustion inspection with minimum downtime can be achievable based on the above factors. Contact your local GE Energy Services representative for the specific man-hours and recommended crew size for your specific unit.

Depending upon the extent of work to be done during each maintenance task, a cooldown period of 4 to 24 hours may be required. This time can be utilized productively for job move-in,

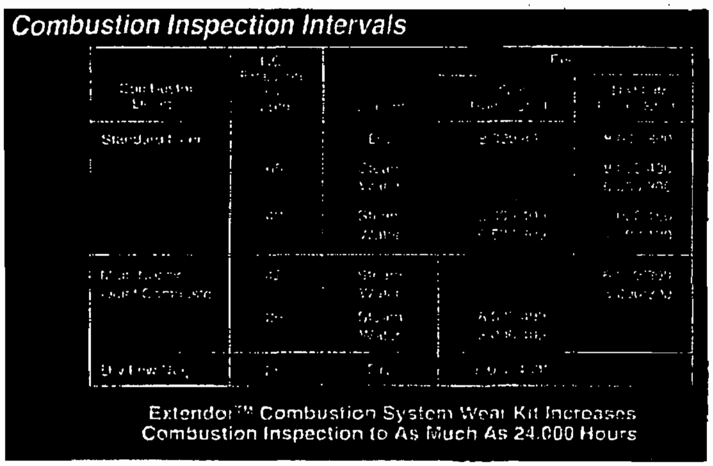

Figure 46. Combustion inspection intervals - MS7001EA

correct tagging and locking equipment out-of-service and general work preparations. At the conclusion of the maintenance work and systems check out, a turning gear time of two to eight hours is normally allocated prior to starting the unit. This time can be used for job clean-up and arranging for any repairs required on removed parts.

Local GE field service representatives are available to help plan your maintenance work to reduce downtime and labor costs. This planned approach will outline the renewal parts that may be needed and the projected work scope, showing which tasks can be accomplished in parallel and which tasks must be sequential. Planning techniques can be used to reduce maintenance cost by optimizing lifting equipment schedules and manpower requirements. Precise estimates of the outage duration, resource requirements, critical-path scheduling, recommended replacement parts, and costs associated with the inspection of a specific installation may be obtained from the local GE field services office.

Conclusion

GE heavy-duty gas turbines are designed to have an inherently high availability. To achieve maximum gas turbine availability, an owner must understand not only his equipment, but the factors affecting it. This includes the training of operating and maintenance personnel, following the manufacturer's recommendations, regular periodic inspections and the stocking of spare parts for immediate replacement. The recording of operating data, and analysis of these data, are essential to preventative and planned maintenance. A key factor in achieving this goal is a commitment by the owner to provide effective outage management and full utilization of published instructions and the available service support facilities.

It should be recognized that, while the manufacturer provides general maintenance recommendations, it is the equipment user who has the major impact upon the proper maintenance and operation of equipment. Inspection intervals for optimum turbine service are not fixed for every installation, but rather are developed through an interactive process by each user, based on past experience and trends indicated by key turbine factors.

The level and quality of a rigorous maintenance program have a direct impact on equipment reliability and availability. Therefore, a rigorous maintenance program which optimizes both maintenance cost and availability is vital to the user. A rigorous maintenance program will minimize overall costs, keep outage downtimes to a minimum, improve starting and running reliability and provide increased availability and revenue earning ability for GE gas turbine users.

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Appendix

A) Example—Maintenance Interval Calculation

An MS7001EA user has accumulated operating data since the last hot gas path inspection and would like to estimate when the next one should be scheduled. The user is aware from GE publications that the normal HGP interval is 24,000 hours if operating on natural gas, no water or steam injection, base load. Also, there is a 1200 start interval, based on normal start-ups, no trips, no emergency starts. The actual operation of the unit since the last hot gas path inspection is much different from the GE "baseline case."

Annual hours on natural gas, base load
= G = 3200 hr/yr
Annual hours on light distillate
= D = 350 hr/yr
Annual hours on peak load
= P = 120 hr/yr

Steam injection rate
= I = 2.4%

Also, since the last hot gas path inspection,

The annual number of normal starts is
= NB = 100/yr

The annual number of peak load starts
= NP = 0/yr

The annual number of part load starts
= NA = 40/yr

The annual number of emergency starts
= E = 2/yr

The annual number of fast load starts
= F = 5/yr

The annual number of trips from load ($a_T = 8$)
= T = 20/yr

For this particular unit, the second and third-stage nozzles are FSX-414 material. The unit operates on "dry control curve."

From *Figure 42*, at a steam injection rate of 2.4%, the value of "M" is. 18, and "K" is.6.

From the hours-based criteria, the maintenance factor is determined from *Figure 42*.

$$MY = \frac{(.6+.18\,(2.4))\times(3200+1.5(350)+6(120))}{(3200+350+120)}$$

MF = 1.25

The hours-based adjusted inspection interval is therefore,

H = 24,000/1.25

H = 19,200 hours [Note, since total annual operating hours is 3670, the estimated time to reach 19,200 hours is 5.24 years (19,200/3670).]

From the starts-based criteria, the maintenance factor is determined from *Figure 43*.

$$MY = \frac{(100+.5\,(40)+20\,(2)+2\,(5)+8\,(20))}{(100+40+2+5+20)}$$

MF = 2.0

The adjusted inspection interval based on starts is,

S = 1200/2.0

S = 600 starts [Note, since the total annual number of starts is 167, the estimated time to reach 600 starts is 600/167 = 3.6 years.]

In this case, the starts-based maintenance factor is greater than the hours maintenance factor and therefore the inspection interval is set by starts. The hot gas path inspection interval is 600 starts (or 3.6 years).

B) Definitions

Reliability: Probability of not being forced out of service when the unit is needed – includes forced outage hours (FOH) while in service, while on reserve shutdown and while attempting to start normalized by period hours (PH)-units are %:

Reliability = (1-FOH/PH) (100)

FOH = total forced outage hours

PH = period hours

Availability: Probability of being available, independent of whether the unit is needed-includes all unavailable hours (UH) – normalized by period hours (PH) – units are %:

Availability = (1-UH/PH) (100)

UH = total unavailable hours (forced outage, failure to start, scheduled maintenance hours, unscheduled maintenance hours)

PH = period hours

Equivalent Reliability: Probability of a multi-shaft combined-cycle power plant not being totally forced out of service when the unit is required includes the effect of the gas and steam cycle MW output contribution to plant output - units are %:

Equivalent Reliability =

$$[1-\left[\frac{GT\ FOH}{GT\ PH} + B\left(\frac{HRSG\ FOH}{B\ PH} + \frac{ST\ FOH}{ST\ PH}\right)\right] \times 100]$$

GT FOH = Gas Turbine Forced Outage Hours

GT PH = Gas Turbine Period Hours

HRSG FOH = HRSG Forced Outage Hours

B PH = HRSG Period Hours

ST FOH = Steam Turbine Forced Outage Hours

ST PH = Steam Turbine Period Hours

B = Steam Cycle MW Output Contribution (normally 0.30)

Equivalent Availability: Probability of a multi-shaft combined-cycle power plant being available for power generation-independent of whether the unit is needed-includes all unavailable hours—includes the effect of the gas and steam cycle MW output contribution to plant output units are %:

Equivalent Availability =

$$[1-\left[\frac{GT\ UH}{GT\ PH} + B\left(\frac{HRSG\ UH}{GT\ PH} + \frac{ST\ UH}{ST\ PH}\right)\right] \times 100]$$

GT UH = Gas Turbine Unavailable Hours

GT PH = Gas Turbine Period Hours

HRSG UH = HRSG Total Unavailable Hours

ST UH = Steam Turbine Unavailable Hours

ST PH = Steam Turbine Forced Outage Hours

B = Steam Cycle MW Output Contribution (normally 0.30)

MTBF-Mean Time Between Failure: Measure of probability of completing the current run. Failure events are restricted to forced outages (FO) while in service – units are service hours:

MTBF = SH/FO

SH = Service Hours

FO = Forced Outage Events from a Running (On-line) Condition

Service Factor: Measure of operational use, usually expressed on an annual basis-units are %:

SF = SH/PH x 100SH = Service Hours on an annual basis

PH = Period Hours (8760 hours per year)

Operating Duty Definition:

Duty	Service Factor	Fired Hours/Start
Stand-by	< 1%	1 to 4
Peaking	1% - 17%	3 to 10
Cycling	17% - 50%	10 to 150
Continuous	> 90%	>> 150

List of Figures

For further information, contact your GE Field Sales Representative or write to GE Power Systems Marketing

GE Power Systems

GE Power Systems
4200 Wildwood Parkway
Atlanta, GA 30339

GER 3620G, 9/00 (2.5M)

GE Power Systems
Gas Turbine

Inspection and Maintenance Instructions For MS-7001FA+ and MS-7001FA+e Gas Turbines Dual Fuel With Dry Low NOx

GEK 107535
Rev. 0

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NEW FORMAT

The Combustion Inspection, Hot Gas Path Inspection and Major Inspection sections of this manual have been formatted to separate the Disassembly, Inspection, and Reassembly Operations for each inspection. The figure numbers and page numbers have also been revised to follow this format.

A "D" preceding a figure or page number is used for the Disassembly section, an "I" is used for the Inspection section, an "R" is used for the Reassembly section, and an "SC" is used for the Startup Checks section.

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TABLE OF CONTENTS

Inspection and Maintenance Instructions

MAJOR INSPECTION

LIST OF ILLUSTRATIONS

LIST OF TABLES

NOTES, CAUTIONS AND WARNINGS

Notes, Cautions and Warnings will be found throughout this Maintenance Publication. It is important that the significance of each is thoroughly understood by personnel using these Maintenance Procedures. Their definitions are as follows:

Note: **Highlights an essential element of a procedure to assure correctness.**

CAUTION

Indicates a procedure or practice, which if not strictly observed, could result in damage or destruction of equipment.

WARNING

Indicates a procedure or practice, which could result in injury to personnel or loss of life if not followed correctly.

SAFETY

This publication is designed to provide safe procedures and processes for accomplishing the maintenance instructions described herein. It is important, therefore, that the warnings, cautions, and notes in these procedures be thoroughly understood and observed by the personnel performing maintenance. Changes or additions deemed necessary for proper maintenance and/or suggested safety improvements should be submitted to:

Manager: Technical Communications and Publishing
GE Company
Building 53, Room 229
1 River Road
Schenectady, New York 12345

Note: **All dimensions called for throughout the maintenance publication are in S.A.E. units first, followed by metric (where applicable) in brackets [ ].**

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ATTACHMENT L

COMBUSTION TURBINE DESIGN INFORMATION

Table A-1. Design Information and Stack Parameters for Vandolah Power
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	179.2	172.2	156.6
Net heat rate (Btu/kWh, LHV)	9,319	9,361	9,591
(Btu/kWh, HHV)	10,344	10,391	10,646
Heat Input (MMBtu/hr, LHV)	1,670	1,612	1,502
(MMBtu/hr, HHV)	1,854	1,789	1,667
Fuel heating value (Btu/lb, LHV)	20,751	20,751	20,751
(Btu/lb, HHV)	23,006	23,006	23,006
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	4,063,400	3,919,300	3,672,900
- provided	3,694,000	3,563,000	3,339,000
Temperature (°F)	1,097	1,113	1,135
Moisture (% Vol.)	7.9	8.6	10.3
Oxygen (% Vol.)	12.60	12.50	12.20
Molecular Weight	28.44	28.34	28.16
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,670	1,612	1,502
Heat content (Btu/lb, LHV)	20,751	20,751	20,751
Fuel usage (lb/hr)- calculated	80,478	77,683	72,382
CT Stack			
CT- Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
Turbine Flow Conditions (CT Stack-Unit 4 only)			
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	4,063,400	3,919,300	3,672,900
Temperature (°F)	1,097	1,113	1,135
Molecular weight	28.44	28.34	28.16
Volume flow (acfm)- calculated	2,706,395	2,645,986	2,530,918
(ft3/s)- calculated	45,107	44,100	42,182
Velocity (ft/sec)	118.7	116.0	111.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 1998.

Table A-13. Design Information and Stack Parameters for Vandolah Power
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	183.9	181.9	171.2
Net heat rate (Btu/kWh, LHV)	10,103	9,929	9,988
(Btu/kWh, HHV)	10,710	10,524	10,588
Heat Input (MMBtu/hr, LHV)	1,858	1,806	1,710
(MMBtu/hr, HHV)	1,969	1,914	1,813
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	4,230,600	4,081,000	3,825,800
- provided	3,846,000	3,710,000	3,478,000
Temperature (°F)	1,076	1,094	1,121
Moisture (% Vol.)	11	11.7	13.3
Oxygen (% Vol.)	11.20	11.04	10.60
Molecular Weight	28.33	28.25	28.06
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,858	1,806	1,710
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	101,530	98,689	93,443
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
Turbine Flow Conditions			
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	4,230,600	4,081,000	3,825,800
Temperature (°F)	1,076	1,094	1,121
Molecular weight	28.33	28.25	28.06
Volume flow (acfm)- calculated	2,790,601	2,731,215	2,622,427
(ft3/s)- calculated	46,510	45,520	43,707
Velocity (ft/sec)	122.4	119.7	115.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 1999; Golder Associates, 1999

ATTACHMENT M

ACID RAIN PERMIT APPLICATION

Acid Rain Part Application

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

This submission is: ☐ New ■ Revised

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

Plant Name **Vandolah Power Project**	State **FL**	ORIS Code **55415**

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
GT101	Yes		
GT201	Yes		
GT301	Yes		
GT401	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

Vandolah Power Project
Plant Name (from Step 1)

STEP 3
Read the standard requirements

Acid Rain Part Requirements

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

Monitoring Requirements

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

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain part application, the Acid Rain part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the Department: .
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

STEP 3, Cont'd.

Vandolah Power Project
Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date

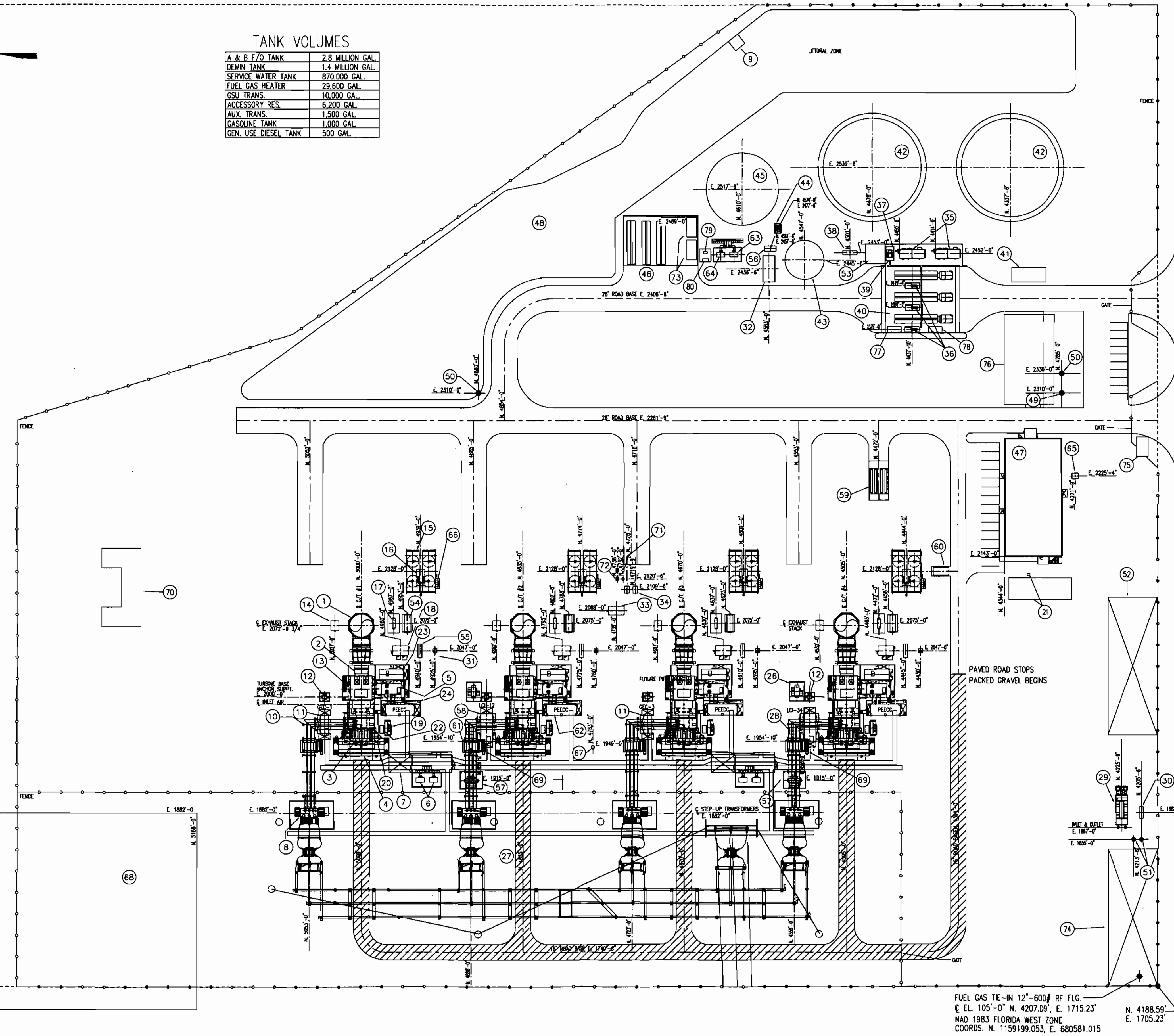
Certification

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

Name DOUGLAS A. JENSEN	
Signature	Date 6/4/07

TANK VOLUMES

A & B F/O TANK	2.8 MILLION GAL.
DEMIN TANK	1.4 MILLION GAL.
SERVICE WATER TANK	870,000 GAL.
FUEL GAS HEATER	29,600 GAL.
GSU TRANS.	10,000 GAL.
ACCESSORY RES.	6,200 GAL.
AUX. TRANS.	1,500 GAL.
GASOLINE TANK	1,000 GAL.
GEN. USE DIESEL TANK	500 GAL.



DESCRIPTIONS CONT.

56. SERVICE WATER PUMPS (510-P-0003A/B)
57. AUXILIARY TRANSFORMER
58. EXCITATION & LCI COMPARTMENT
59. H2 BULK STORAGE
60. CO2 BULK STORAGE
61. GENERATOR CIRCUIT BREAKER
62. PEECC BLDG.
63. STATION SERVICE TRANSFORMER 5 (SST#5)
64. STATION SERVICE TRANSFORMER 6 (SST#6)
65. ALTERNATE SOURCE TRANSFORMER 7 (AST#7)
66. GLYCOL MCC
67. EVAPORATOR COOLERS DRAIN SUMP (521-CO-0001)
68. EVAPORATION POND
69. LCI COOLER (342-CFN-10D1 & 3001)
70. CONEX STORAGE
71. AIR RECEIVER (543-VSL-0001)(543-VSL-0002)
72. INSTRUMENT AIR DRYER SKID (543-DRY-0D01)
73. EDG 1 AND 2
74. FGT GAS YARD
75. GUARD HOUSE
76. EAST WAREHOUSE
77. 1,000 GAL. GASOLINE TANK
78. 500 GAL. DIESEL TANK
79. EDG TRANSFORMER (SST GEN)
80. S1 EDG ISOLATION SWITCH
81.
82.
83.
84.
85.
86.
87.
88.

NOTES:

1. POINT OF SUPPORT EL. 104'-0" UNLESS NOTED.

25 0 25 50 75 100
1" = 50' - 0"

DESCRIPTIONS

1. EXHAUST STACK (357-STA-1001, 2001, 3001, 4001)
2. COMBUSTION TURBINE(311-CT-1001,2001,3001,4001)
3. COMBUSTION TURBINE GENERATOR (312-TG-1001, 2001, 3001, 4001)
4. INTAKE AIR FILTER (351-FLT-1001, 2001, 3001, 4001)
5. ACCESSORY MODULE
6. STATION SERVICE TRANSFORMER
7. POWER CONTROL ROOM/ELECTRICAL SWITCHGEAR BUILDING (170-BLDG-0001 & 0002)
8. GENERATOR STEP-UP TRANSFORMER
9. OUT FALL
10. ISO PHASE BUS OUCT
11. GENERATOR EXCITATION COMPARTMENT (GEC)
12. EXCITATION TRANSFORMER
13. TURBINE COMPARTMENT ENCLOSURE
14. CEMS BUILOING (519-SAM-0001,0002,0003, & 0004)
15. GLYCOL COOLERS (464-CFN-1001, 2001, 3001, 4001)
16. GLYCOL COOLER PUMPS (464-P-1001A/B, 2001A/B, 3001A/B, 4001A/B)
17. CT DRAIN TANK WITH SUMP (371-TNK-1001, 2001, 3001, 4001)
18. WATER INJECTION SKIO (364-SKO-1001,2001,3001,4001)
19. FIRE PROTECTION/CO2 SKID(372-SKO-1001,2001,3001,4001)
20. CO2 BOTTLES
21. LIFT STATION AND LEACH FIELD
22. H2 BOTTLES
23. LIQUID FUEL / ATOM. AIR MODULE
24. SAFETY SHOWER / EYEWASH STATION
26. ISOLATION TRANSFORMER
27. SWITCHYARD
28. DC LINK REACTOR
29. FUEL GAS HEATER SKID (S61-SKD-0001)
30. FUEL GAS DRAIN TANK (561-TNK-0001)
31. FUEL GAS SCRUBBER (561-SCB-1001, 2001, 3001, 4001)
32. FIRE PUMP HOUSE ENCLOSURE (572-SKD-0001)
33. WATER WASH SKID (374-SKD-0001)
34. AIR COMPRESSORS (543-CMP-0001 A/B)
35. FUEL OIL FORWARDING PUMP SKID (562-SKD-0001A/B)
36. FUEL OIL UNLOADING PUMPS (562-P-0001A/B/C)
37. FUEL TRUCK UNLOADING SUMP PUMP (520-P-0002)
38. OIL / WATER SEPARATOR (521-SEP-0001)
39. FUEL TRUCK UNLOADING SUMP (520-CO-0002)
40. COVERED FUEL OIL UNLOADING AREA
41. FIREWATER FOAM HOUSE (572-BLDG-0001)
42. FUEL OIL STORAGE TANKS (562-TNK-0001A/B)
43. SERVICE WATER / FIRE WATER STORAGE TANK (510-TK-0001)
44. WATER WASH FEED/DEMIN PUMPS (513-P-0D01A/B/C)
45. DEMINERALIZED WATER STORAGE TANK (513-TNK-00D1)
46. MOBILE DEMIN WATER TRAILERS
47. ADMIN BUILDING
48. DETENTION POND
49. POTABLE WATER WELL PUMP (577-P-0001)
50. SERVICE WATER WELL PUMPS (510-P-0001A/B)
51. FUEL GAS SEPARATOR/FILTER (561-SEP-D001 A/B)
52. PGS GAS YARD (TECO)
53. 2D' X 2D' OIL BARREL STORAGE PAD
54. GAS TURBINE WATER WASH DRAIN TANK (371-TNK-1002, 2002, 3002, 4002)
55. FUEL OIL MANAGEMENT SKID(562-SKD-1001,2001,3001,40D1

REV	DATE	DESCRIPTION	DRAWN	CHECKED	ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
2	09/06/01	GENERAL REVISION	TD	RN	SL	MF	WB
1	08/23/01	GENERAL REVISION	TD	RN	SL	MF	WB
0	07/17/01	ISSUE FOR CONSTRUCTION	TD	RN	SL	MF	WB
5	03/29/07	GENERAL REVISION	WS		SP	SP	AN
4	03/06/02	GENERAL REVISION	TD	RN	SL	MF	WB
3	10/11/01	REVISED FUEL GAS COORDINATES	TD	RN	SL	MF	WB

DRAWN BY	T. DEBLANC	DATE 02/28/01
CHECKED BY	R. NORTHAM	DATE 07/17/01
ENGINEER	S. LEONARD	DATE 07/17/01
PROJECT ENGINEERING MANAGER	M. FRELICH	DATE 07/17/01
PROJECT MANAGER	W. BIGGS	DATE 07/17/01

PARSONS
Parsons Energy and Chemicals Group, Inc.
Houston Operations

Gemma
Gemma Power Systems, LLC
ELPASO ENERGY INTERNATIONAL
VANDOLAH POWER PROJECT

PARSON'S PROJECT NO. 156096

EQUIPMENT LOCATION PLAN

SCALE 1" = 50'-0"

PARSON'S DWG. NO. VAND-1-DW-110-002-001 REVISION 5