CALPINE

CALPINE CENTER
717 TEXAS AVENUE
SUITE 1000
HOUSTON, TEXAS 77002
713.830.2000
713.830.2001 (FAX)

June 27, 2007

RECEIVED
JUN 28 2007
BUREAU OF AIR REGULATION

VIA FEDERAL EXPRESS

Mr. Jeff Koerner, P.E.
Florida Department of Environmental Protection
Bureau of Air Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Application for Renewal of Title V Operating Permit
Santa Rosa Energy Center / Santa Rosa Energy, LLC
Facility ID 1130168 — Project No.: 1130168-007-AV

Dear Mr. Koerner:

Please find enclosed an application for the renewal of a Title V Operating Permit for the Santa Rosa Energy Center, which is owned by Santa Rosa Energy, LLC.

We hope that the information supplied will meet the department's need to evaluate this request. If you have questions or need additional information, please do not hesitate to contact me via telephone at (713) 570-4795 or via email at jgoodwin@calpine.com; or Heidi Whidden at (713) 570-4829 or hwhidden@calpine.com.

Sincerely,
Santa Rosa Energy, LLC

Jason M. Goodwin, P.E.
Director - Environmental, Health & Safety
Eastern Power Region

Enclosure

bc: Ron Rose
Dane Hill
Heidi Whidden
(w/ enclosure)

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BUREAU OF AIR REGULATION

Santa Rosa Energy Center
Calpine Corporation

Title V Air Operating Permit Renewal Application

June 2007

Table of Contents

1. Application Summary

The Santa Rosa Energy Center (the Facility), a combined cycle cogeneration facility, is owned by Calpine Corporation and operated by Calpine Operating Services Company, Inc. The facility is located near Pace, Florida on a leased portion of the Sterling Fibers manufacturing facility.

Pursuant to Title V of the federal Clean Air Act and Amendments (CAAA) of 1990, this report constitutes a renewal application for an operation permit for the Facility. The Facility is classified as major stationary source as defined in the Florida Administration Code, Chapter 62-213, FAC and is therefore required to obtain a major source operating permit. The cogeneration facility is a Title V major source as facility-wide potential emissions exceed the major source emission threshold of 100 tons per year for oxides of nitrogen (NOx) and carbon dioxide (CO). The Facility began compliance with their air construction permit (PSD-FL-243) by June 30, 2002 and is currently operating under their initial Title V permit (1130168-004-AV). An application for renewal of the Title V permit is required at least 180 days prior to expiration of the current Title V, in this case July 1, 2007. A copy of the current PSD and Title V permit is located in Appendix A. With this document, Calpine has provided the data, demonstrations, certifications and application forms required.

1.1. Site Description

The Facility is located near Pace, Florida in Santa Rosa County. The Facility is located on land leased from Sterling Fibers within the manufacturing plant boundary. An area map showing the location of the Facility on the U.S Geological Survey 7.5 minute series topographic map is provided in Appendix B to this application. A plot plan of the Facility showing the approximate location of the defined emission points is also located in Appendix B.

1.2. Description of Expected Operations

The primary components of the Facility are the combustion turbine, steam turbine, heat recovery generator (HRSG) and cooling tower. A small natural gas preheater (dew point heater) is also included. The HRSG was initially permitted to include the installation and use of duct burners. The duct burners have not been installed and were not included in the initial Title V application, nor this application. The combustion turbine operates exclusively on natural gas. The combustion turbine has an electric generation capacity of approximately 167 MW. Emissions of NOx are reduced from the combustion turbine by the use of Dry Low NOx combustors.

1.3. Request for Permit Application Shield

Section 503(d) of the CAAA provides that once a timely and complete application for an operating permit has been filed, the applicant is shielded from enforcement action for operating without a permit until the permit has been issued or other action has been taken on the application. Florida Administration Code incorporates the concept of an application shield for sources required to obtain a major source operating permit.

The Facility requests that this permit application shield be established for the Facility on the presumption that FDEP will affirm that the application is administratively complete.

1.4. Request for Permit Shield

Section 504(f) of the CAAA defines the permit shield provision, whereby the permitting authority is empowered to provide that compliance with a Part 70 permit shall be deemed in compliance with all other applicable provisions of the Act. Florida Administration Code (Chapter 62-213.460) incorporates the concept of a permit shield. A provision stating that compliance with conditions of the major source operating permit shall be deemed compliance with all applicable requirements (as of the date of permit issuance) provided that the following conditions are met:

- Such applicable requirements are identified and included in the permit; and
- FDEP, in acting on the permit application or revision, includes a determination in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

The Facility is requesting through this application that FDEP include permit shield provisions in its Operating Permit consistent with this regulation. A listing of applicable regulations is presented on form 62-210.900(1), included in Section 6.

2. Process Description

The facility is operated under Standard Industrial Classification Code 4911, Electric Services. The primary components of the facility are a combustion turbine, steam turbine, and an unfired HRSG. The combustion turbine is a General Electric Frame 7F design with an electric generation capacity of approximately 178 MW. The combustion turbine combusts natural gas exclusively. Reduction of NOx emissions from the combustion turbine is achieved via the use of Dry Low NOx combustors for natural gas firing which will reduce NOx emitted to less than 9 ppmvd at 15% O_2.

The HRSG is a triple pressure unit providing its high pressure and intermediate pressure steam to the deaerator with a small amount going to the low pressure section of the steam turbine or to Sterling Fibers for process use. During operation of the Sterling Fibers facility, the Facility will route most of the intermediate pressure steam from the HRSG to the Sterling Fibers process steam header for process use. Operations and maintenance procedures are available in Appendix C.

The combustion turbine fires natural gas with the exhaust air stream directed to the HRSG for steam generation. A fuel analysis is available in Appendix D.

Start-up operations for the turbine require up to 240 minutes for the system to reach steady state operation from the initial fuel firing. Shut-down operations require up to 180-minutes to lower the system from steady-state operation to cessation of fuel firing. Start-up and shut-down procedures are available in Appendix C.

A process flow diagram depicting the major process units and emissions points is provided in Appendix B to supplement this description.

3. Emissions Inventory

Emissions of both criteria pollutants (PM, SO2, NOx, CO) and non-criteria pollutants (VOC and HAP) are estimated. The emissions from criteria pollutants are based on the limits established in PSD permit PSD-FL-253, issued December 4, 1998 and the current Title V permit (1130168-004-AV).

3.1. Air Emissions Summary

Emissions from the combustion turbine are generated from firing natural gas. Combustion emission estimates are generally based on manufacturer supplied data, consistent with AP-42 emission factors compiled by the US EPA.

Table 3-1 provides a listing of the potential emissions for PM, SO2, NOx, CO, VOC and HAPS) from the Facility. The emission levels presented for criteria pollutants reflects existing permit limits or when no unit-specific emission limits apply, the maximum anticipated emissions at full capacity assuming continuous operation. The potential HAP emissions are based on AP-42 emission factors with the exception of the formaldehyde emission factor, which is provided by the California Air Resource Board (CARB). Documentation for all emissions represented in this application is provided in Section 6 (Forms III F). HAP emissions represented in this application is provided in Appendix D.

Table 3-1 Potential Combustion Turbine Emissions of PM, SO2, NOx, CO, VOC and HAP

Pollutant	Potential Emissions (TPY)	Major Source (Yes/No)
PM	42	No
SO2	33	No
NOx	381	Yes
CO	127	Yes
VOC	13	No
Total HAP	3.6	No

Emissions for other listed and insignificant emissions sources were not quantified in the initial permitting. A list of these units is shown in Appendix E.

4. Regulatory Review

A key objective of a Title V operating permit application is to compile all applicable Clean Air Act derived requirements into one document. Conceptually, these requirements can largely be categorized as (1) emission limits and work practice standards, or (2) testing, monitoring, recordkeeping or reporting requirements. In order to compile a list of all the requirements a facility must comply with, it is first necessary to determine which Federal and State air regulations apply to the facility as a whole, or to individual emission units. This section documents the applicability determinations made of all Federal and State air quality regulations. Specific listings of applicable regulations are found in Appendix F.

4.1. Federal Regulatory Applicability

Applicability or non-applicability of the following federal regulatory programs are addressed: New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPS), and Acid Rain Program.

4.1.1. New Source Performance Standards (NSPS)

NSPS, codified in 40 CFR Part 60, require new, modified, or reconstructed sources to control emissions to the level achievable by best demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, except as noted. The following is a summary of the NSPS that apply to the Facility.

4.1.1.1.NSNPS Subpart A-General Provisions

Any source subject to a source-specific NSPS (in the case of the Facility, NSPS GG) is also subject to the general provisions of NSPS Subpart A. NSPS Subpart A generally requires the following of facilities subject to a source-specific NSPS:

- Initial construction/reconstruction notification;
- Initial start-up notification;
- Performance tests;
- Performance test date initial notification;
- General monitoring requirements;
- General recordkeeping requirements; and
- Semiannual monitoring system and/or excess emission reports.

All of these requirements do not necessarily apply to all facilities subject to a source-specific NSPS. Source-specific NSPS provisions can supersede NSPS Subpart A as noted in the relevant Subpart.

4.1.1.2.NSPS Subpart GG-Standards of Performance for Stationary Gas Turbines

NSPS Subpart GG provides standards of performance for stationary gas turbines with a heat input at peak load equal to or greater than 10.7 GJ/hr (10.1 MMBtu/hr) based on the lower heating value of the fuel fired. The combustion turbine has a rated heat input of 1,780 MMBtu/hr (HHV) when firing natural gas, thus it is subject to this regulation. The applicable NOx emission standard for natural gas combustion is 114 ppmvd.

The requirements for SO2 under this subpart are an emission limit of 150 ppmvd @ 15% O2 or a fuel sulfur limit of 0.8% by weight.

4.1.2. National Emission Standards for Hazardous Air Pollutants (NESHAPS)

The NESHAP, like NSPS, establish emission standards and work practice requirements for specific source categories and are codified at 40 CFR Part 63. However, the target of regulation under the NESHAP is emissions of any one of the 188 defined HAPs listed in Section 112(b) of the Clean Air Act. NESHAPs require that an affected source meet Maximum Achievable Control Technology (MACT) standards to minimize HAP emissions. MACT typically represents an emission limit and/or work practice standard that has been demonstrated to minimize HAP emissions form a particular process or device. A major source not yet regulated by a source specific NESHAP may still be required to meet MACT pursuant to Section 112(g) of the Clean Air Act, which provides for case-by-case MACT evaluations of new major HAP sources.

As with NSPS standards, NESHAPs are primarily developed for particular industrial source categories. Therefore, the applicability of a particular NESHAP to a facility can be readily ascertained based on the industrial source category covered. All NESHAP regulations, both 40 CFR Part 61 and 63 are categorically not applicable to energy generation facilities.

4.1.3. Acid Rain Regulations

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR Part 72) of the Clean Air Act Amendments of 1990 established the Acid Rain Program (ARP) to substantially reduce SO2and NOx emissions from electric utility plants. Affected units are specifically listed in Tables 1 or 2 of 40 CFR Part 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the acid Rain Program in general applies to fossil fuel-fired combustion sources that drive generators for the purpose of generating electricity for sale. Any piece of equipment is subject to the regulations if it is a "utility unit". The regulations define utility unit to mean, "a unit owned or operated by a utility…[t]hat serves a generator in any State that produces electricity for sale." A "utility" is defined as "any person that sells electricity." As such the combustion turbine along with the HRSG, referred to as a combined cycle combustion turbine (CCCT), at the Facility is subject to the APP regulations since it is a fossil fuel –fired combustion device that generates electricity to be sold (i.e. utility unit). Accordingly, all subparts of the Acid Rain Program are potentially applicable to the Facility. The potentially applicable subparts are identified as follows:

- 40 CFR Part 72, Remits Regulations.
- 40 CFR Part 73, Remits Regulations
- 40 CFR Part 74, Remits Regulations
- 40 CFR Part 75, Remits Regulations
- 40 CFR Part 76, Remits Regulations
- 40 CFR Part 77, Remits Regulations
- 40 CFR Part 78, Remits Regulations

5. Compliance Certification and Plan

The permit application requires the inclusion of a compliance plan and certifications. The following items list steps to be flowed to meet applicable regulatory requirements. Additional items are included in the appendices as discussed below.

- The Facility will monitor and ensure compliance with the majority of the applicable requirements via the continuous emissions monitor (CEM) for the combustion turbine stack.
- Required Acid Rain monitoring reports will be submitted electronically each quarter using data supplementing procedures per 40 CFR Part 75. Additionally, excess emissions reports are submitted to the FDEP quarterly as required in the Facility Title V Permit Condition A.17.
- As required by the current Title V permit, the CEM is installed on the combustion turbine exhaust stack, subject to the requirements of the Acid Rain Permitting program and monitoring requirements. Procedures specified under 40 CFR Part 75, Continuous Emission Monitoring are followed. This compliance certification presumes that the monitoring requirements included in the existing facility permits and the Acid Rain Permitting program meet the intent and requirement of the applicable NSPS requirements.
- In general, all monitoring, recordkeeping and reporting requirements are met via compliance with the Acid Rain Permitting program and the applicable permit requirements, stack testing, and CEMS. Compliance certifications presented in this application presume that excess emissions reporting in accordance with the permit emission limitations and compliance requirements meet the intent of the applicable NSPS requirements.
- The combustion turbine Part 75 Monitoring Plan is attached as Appendix G. Ongoing compliance will be in accordance with the requirements of PSD permit and conditions incorporated in the Title V permit.
- No violations of the referenced permits, plans, or regulations have occurred at the site at the time of this submission.

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

Jason Goodwin, Director-EHS* 6/27/07 Date

*Section 6 contains an updated application for Responsible official form.

6. Permit Application Forms

Department of Environmental Protection

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.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Santa Rosa Energy, LLC	
2. Site Name: Santa Rosa Energy Center	
3. Facility Identification Number: 1130168	
4. Facility Location... *Southwest of Sterling Fibers Inc. within the Plant Boundary* Street Address or Other Locator: 5001 Sterling Way City: Pace County: Santa Rosa Zip Code: 32571	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Heidi M. Whidden
2. Application Contact Mailing Address... Organization/Firm: Calpine Corporation (c/o EHS Department) Street Address: 717 Texas Avenue; Suite 1000 City: Houston State: TX Zip Code: 77002
3. Application Contact Telephone Numbers... Telephone: (713) 570-4829 ext. Fax: (713) 332-5168
4. Application Contact Email Address: hwhidden@calpine.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s): 1130168-007-AV	4. Siting Number (if applicable):

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APPLICATION INFORMATION

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

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	One nominal 167 Megawatt Gas Combined-Cycle Turbine Electrical Generator with Heat Recovery Steam Generator		
003	Wet Cooling Tower		

Application Processing Fee

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

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : Jason Goodwin
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Calpine Corporation (c/o EHS Department) Street Address: 717 Texas Avenue; Suite 1000 City: Houston State: TX Zip Code: 77002
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (713) 570-4795 ext. Fax: (713) 332-5168
4.	Owner/Authorized Representative Email Address: jgoodwin@calpine.com
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] 6/27/07 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:
   Jason Goodwin

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.
   - [x] The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: Calpine Corporation (c/o EHS Department)
   Street Address: 717 Texas Avenue; Suite 1000
   City: Houston State: TX Zip Code: 77002

4. Application Responsible Official Telephone Numbers...
   Telephone: (713) 570-4795 ext. Fax: (713) 332-5168

5. Application Responsible Official Email Address: jgoodwin@calpine.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.

   ______________________ 6/27/07
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: Benjamin M. H. Borsch Registration Number: 43875
2.	Professional Engineer Mailing Address... Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 1408 North Westshore Boulevard Suite 115 City: Tampa State: Florida Zip Code: 33607
3.	Professional Engineer Telephone Numbers... Telephone: (813) 289 - 9338 ext. Fax: (813) 289 - 9388
4.	Professional Engineer Email Address: bborsch@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 [X], if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance 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.

Benjamin M. H. Borsch 6/25/07

Signature Date

(seal)

BENJAMIN M.H. BORSCH
CERTIFICATE
No. 43875
STATE OF FLORIDA

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

<table>
<tr><td colspan="2">1. Facility UTM Coordinates...
Zone 16 East (km) 488.974
North (km) 3,381.526</td><td colspan="2">2. Facility Latitude/Longitude...
Latitude (DD/MM/SS) 30°33'58.3"
Longitude (DD/MM/SS) 87°06'54.1"</td></tr>
<tr><td>3. Governmental Facility Code:
0</td><td>4. Facility Status Code:
A</td><td>5. Facility Major Group SIC Code:
49</td><td>6. Facility SIC(s):
4911</td></tr>
<tr><td colspan="4">7. Facility Comment :</td></tr>
</table>

Facility Contact

1. Facility Contact Name: Dane Hill; Facility Environmental Coordinator (O&M Manager)
2. Facility Contact Mailing Address... Organization/Firm: Calpine Operating Services Company, Inc. Street Address: 1003 Papermill Road City: Mobile State: AL Zip Code: 36610
3. Facility Contact Telephone Numbers: Telephone: (251) 330-1031 ext. Fax: (251) 330-1093
4. Facility Contact Email Address: dhill@calpine.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: Ronald Rose
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Calpine Operating Services Company, Inc. Street Address: 5001 Sterling Way City: Pace State: FL Zip Code: 32571
3. Facility Primary Responsible Official Telephone Numbers... Telephone: (850) 995-2125 ext. Fax: (251) 330-1093
4. Facility Primary Responsible Official Email Address: rrose@calpine.com

FACILITY INFORMATION

Facility Regulatory Classifications

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

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: Please see Section 3.1.2 of the report text for additional information.	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	A	N
NOx	A	N
PM	B	N
PM10	B	N
SO2	B	N
VOC	B	N
HAP	B	N

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps **Not Applicable**

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Appendix B [ ] 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) [x] Attached, Document ID: Appendix 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) [x] Attached, Document ID: Section 5 of Report Text [ ] Previously Submitted, Date:_

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: [ ] Attached, Document ID:________ [ ] Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): [ ] Attached, Document ID:________
3.	Rule Applicability Analysis: [ ] Attached, Document ID:_________
4.	List of Exempt Emissions Units (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:_________ [X] Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

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): [x] Attached, Document ID: **Appendix 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): [x] Attached, Document ID: **Appendix F_** ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): [x] Attached, Document ID:_**Section 5 of Report Text**___ 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:________ [x] 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:__________ [x] Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ [x] Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   168 MW (nominal) Natural Gas Fired Combustion Turbine with Heat Recovery Steam Generator

3. Emissions Unit Identification Number: EU001

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	January 2001	April 2002	49	[X] Yes [ ] No

9. Package Unit: Combustion Turbine
   Manufacturer: General Electric Model Number: GE MS7001FA

10. Generator Nameplate Rating: Appr. 167 Simple Cycle and 241 Combined Cycle. Unit is not intended to be operated in simple cycle mode.

11. Emissions Unit Comment:

    The combustion turbine is a General Electric Frame 7FA. The unit has a nominal rating of 167 MW at 100% load, 1780 MMBtu/hr (HHV) at an ambient temperature of 68°F. Generating capacity and heat input will vary with seasonal weather conditions.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Dry Low NOx technology is an integral part of the combustion turbine design and reduces the potential for thermal NOx formation through combustion control and burner design. In addition clean fuel (natural gas) will be combusted in the combustion turbine. Code (030) is the closest match for low sulfur fuel.
2. Control Device or Method Code(s): 025

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: Not Applicable		
2. Maximum Production Rate: 189 MW at 40°F ambient temperature (simple cycle)		
3. Maximum Heat Input Rate: 1908 million Btu/hr w/ PWR AUG at 40°F Ambient Temp		
4. Maximum Incineration Rate: pounds/hr Not Applicable tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: The heat input will vary with load conditions and ambient air temperatures. The values presented are based on the maximum load and the lowest average monthly temperature for the site as previously presented to the agency per the manufacturer. Actual maximum operating rates/temperatures have not been determined due to the minimal operation of the unit. The combustion turbine will operate normally above 50% load.		

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: STK001	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

The natural gas fired combustion turbine exhaust gases will pass through the heat recover generator (HRSG) and exit through the stack.

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

EU-001

5. Discharge Type Code: V	6. Stack Height: 200 Feet	7. Exit Diameter: 19 feet
8. Exit Temperature: ~196-216 °F	9. Actual Volumetric Flow Rate: 1,073,204 acfm (see comments)	10. Water Vapor: ~10 %

11. Maximum Dry Standard Flow Rate: 786,315 dscfm (see comments)	12. Nonstack Emission Point Height: Not Applicable feet
13. Emission Point UTM Coordinates... Zone: 16 East (km): 489115.84 North (km): 3381743.8	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) 30/34/05 N Longitude (DD/MM/SS) 87/06/49 W

15. Emission Point Comment:

Stack flow rate is calculated from the combustion turbine exhaust data provided by the manufacturer for operation in the "Power Augmentation Mode".

EMISSIONS UNIT INFORMATION
Section [1] of [2]

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 1_

1. Segment Description (Process/Fuel Type): Natural Gas Combustion for the Combustion Turbine		
2. Source Classification Code (SCC): 2-01-002-01 Internal Combustion Electric Generation, Natural Gas, Turbine	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.908×10^6 scf@1000Btu'scf	5. Maximum Annual Rate: $16{,}714 \times 10^6$ scf@1000Btu'scf	6. Estimated Annual Activity Factor: Not Applicable
7. Maximum % Sulfur: Negligible	8. Maximum % Ash: Negligible	9. Million Btu per SCC Unit: 1000MMBtu/10^6 scf
10. Segment Comment: Several Source Classification Codes (SCC) were close matches to the unit. However, the SCC used is the same as that used for US EPA AP-42 5th Ed. Section 3.1 (Note: vendor emission information was used in calculations for all emission estimates rather than values present in Section 3.1 of AP-42).		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

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
CO	**0**	**030**	**EL**
NOx	**025**	**030**	**EL**
PM	**0**	**030**	**EL**
PM10	**0**	**030**	**EL**
SO2	**0**	**030**	**EL**
VOC	**0**	**030**	**EL**
HAP	**0**	**030**	**NS**
		Note: 030 is used for clean fuel firing	

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: Not Applicable
3. Potential Emissions: 29 lb/hour 127 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: 0.0163 lb/MMBtu Reference: Manufacturer Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Manufacturer Data for CO: 9 ppmvd and 29 lb/hr @ ISO conditions and 1780 MMBtu/hr (HHV)

Annual Emissions Calculation
29 lb/hr * 8760 hr/yr / 2000 lb/ton = 127 ton/yr

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: OTHER BACT	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units: Not to exceed 9 ppmvd @ 15% O_2 and 29 lb/hr	4. Equivalent Allowable Emissions: 29 lb/hour 127 tons/year
5. Method of Compliance: Good combustion practices along with recordkeeping of fuel usage.	
6. Allowable Emissions Comment (Description of Operating Method): Based on PSD and current Title V.	

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):	

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: Not Applicable
3. Potential Emissions: 64.1 lb/hour 280.75 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: 0.036 lb/MMBtu (HHV) Reference: Manufacturer Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Manufacturer Data for NOx: 9 ppmvd and 64.1 lb/hr @ ISO conditions and 1780 MMBtu/hr (HHV)

Annual Emissions Calculation

64.1 lb/hr * 8760 hr/yr / 2000 lb/ton = 280.75 ton/yr

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: OTHER BACT	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units: Not to exceed 9 ppmvd @ 15% O_2 on a 24-hour block average.	4. Equivalent Allowable Emissions: 64.1 lb/hour 280.75 tons/year
5. Method of Compliance: Part 75 NOx CEMS (CEMS are proposed to also be used in lieu of nitrogen fuel sampling)	
7. Allowable Emissions Comment (Description of Operating Method): Allowable emissions are based on PSD and current Title V. They are more stringent than that required in 40 CFR Part 60 Subpart GG, Section 60.332(a)(1) which was calculated to be approximately 114 ppmvd @15% O2 for the worst case load and ambient conditions.	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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	2. Total Percent Efficiency of Control: Not Applicable
3. Potential Emissions: 9.5 lb/hour 41.6 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: 0.0051 lb/MMBtu Reference: Manufacturer Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Manufacturer Data for PM: 9.5 lb/hr less at all loads (front half only).

Annual Emissions Calculation
9.5 lb/hr * 8760 hr/yr / 2000 lb/ton = 41.6 ton/yr

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: OTHER BACT	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units: VE test, not to exceed 10% opacity. Tested via Method 9.	4. Equivalent Allowable Emissions: 9.5 lb/hour 41.6 tons/year
5. Method of Compliance: Good combustion practices along with recordkeeping of fuel usage.	
8. Allowable Emissions Comment (Description of Operating Method): Allowable emissions are based on PSD and current Title V.	

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: PM10	2. Total Percent Efficiency of Control: Not Applicable
3. Potential Emissions: 9.5 lb/hour 41.6 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: 0.0051 lb/MMBtu Reference: Manufacturer Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Manufacturer Data for PM: 9.5 lb/hr less at all loads (front half only).

Annual Emissions Calculation
9.5 lb/hr * 8760 hr/yr / 2000 lb/ton = 41.6 ton/yr

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: OTHER BACT	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units: VE test, not to exceed 10% opacity. Tested via Method 9.	4. Equivalent Allowable Emissions: 9.5 lb/hour 41.6 tons/year
5. Method of Compliance: Good combustion practices along with recordkeeping of fuel usage.	
9. Allowable Emissions Comment (Description of Operating Method): Allowable emissions are based on PSD and current Title V.	

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: Not Applicable
3. Potential Emissions: 10.2 lb/hour 44.5 tons/year	4. Synthetically Limited? ☐ Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: 0.0006 lb/MMBtu Reference: Engineering Calculations	7. Emissions Method Code: 2
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

10.2 lb/hr at ISO conditions based on 2.0 grains sulfur/100 scf natural gas.

Emissions Factor Calculation for Long-Term Emissions
0.02 gr/scf*lb/7000gr*1000scf/MMBtu*64.06mol SO2/32.06 mol S*1780 MMBtu/hr heat input PWG AUG @ 40°F (worst case load)=10.2 lb/hr

Annual Emissions Calculation
10.2 lb/hr * 8760 hr/yr / 2000 lb/ton = 44.5 ton/yr

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: ESCPSD	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units: Natural Gas Usage	4. Equivalent Allowable Emissions: 10.2 lb/hour 44.5 tons/year
5. Method of Compliance: Compliance will be assured by only burning natural gas to fire the combustion turbine and fuel analyses will be completed as required by NSPS rules.	
10. Allowable Emissions Comment (Description of Operating Method): The emission restriction per 40 CFR 60.333(a) is 150 ppmvd@15%O2. Only natural gas will be fired in the combustion turbine and the SO2 emissions will be far less than this standard of the fuel sulfur content limit of 0.8%wt and PSD threshold.	

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: Not Applicable
3. Potential Emissions: 2.9 lb/hour 12.7 tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: 0.0017 lb/MMBtu or 1.7 lb/10^6scf. Natural gas @1000 BTU/scf Reference: Manufacturer Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:
Manufacturer Data for VOC: 1.4 ppm and 2.9 lb/hr

Annual Emissions Calculation
2.9 lb/hr * 8760 hr/yr / 2000 lb/ton = 12.7 ton/yr

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: OTHER BACT	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units: Not to exceed 1.4 ppm and 2.9 lb/hr	4. Equivalent Allowable Emissions: 2.9 lb/hour 12.7 tons/year
5. Method of Compliance: Demonstrated by Initial stack test and good combustion practices along with recordkeeping of fuel usage.	
11. Allowable Emissions Comment (Description of Operating Method): Allowable emissions are based on PSD and current Title V.	

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: HAP	2. Total Percent Efficiency of Control: Not Applicable
3. Potential Emissions: 0.8 lb/hour 3.55 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor: See Appendix D. Reference: AP-42 and CARB	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): Not Applicable tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): Not Applicable tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See Appendix D.	
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: ESCMACT	2. Future Effective Date of Allowable Emissions: Not Applicable
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Good combustion practices along with recordkeeping of fuel usage.	
12. 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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: one per period of 6 min/hour	
4. Method of Compliance: Initial compliance testing then annually in years in which operation of the combustion turbine exceeds 400 hours.	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2__ of __2

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: [ ] Rule [x] Other
3. Allowable Opacity: Normal Conditions: 10 % (6 min average) Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: Initial compliance testing then annually in years in which the operation of the combustion turbine exceeds 400 hours.	
5. Visible Emissions Comment: A 10% VE requirement was placed in the PSD permit to ensure compliance with PM emissions criteria. This requirement is more stringent than the otherwise applicable 20% requirement.	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1__ of 1__

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Provided in the NOx Monitoring Plan in Appendix G. Manufacturer: Model Number:	Serial Number:
5. Installation Date: 5/11/02 (initial certification date)	6. Performance Specification Test Date: 8/1/03 (last RATA)
6. Continuous Monitor Comment: NOx monitoring is required under the Acid Rain rules of 40 CFR Part 72 and 75 for the combustion turbine and is specified in the current Title V Permit.	

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:	

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)
   [X] Attached, Document ID: Appendix 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)
   [X] Attached, Document ID: Attachment D [ ] 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)
   [X] Attached, Document ID: Sections 2 & 5 of Text [ ] 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)
   [X] Attached, Document ID: Attachment C [ ] 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)
   [X] Attached, Document ID: Attachment C [ ] Previously Submitted, Date ________
   [ ] Not Applicable

6. Compliance Demonstration Reports/Records
   [ ] Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________

   [X] Previously Submitted, Date: 9/2003
   Test Date(s)/Pollutant(s) Tested: 8/2003 NOx RATA; 8/2004 VE and CO
   Note: No renewal testing is required for units that did not operate during the year prior (2006) per Title V A.30.
   [ ] 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

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 [x] Attached, Document ID: Attachment F_
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____________ [x] Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: ____________ [x] Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____________ [x] Not Applicable
5. Acid Rain Part Application [x] Certificate of Representation (EPA Form No. 7610-1) [x] Copy Attached, Document ID: Attachment A [x] Acid Rain Part (Form No. 62-210.900(1)(a)) [x] Attached, Document ID: Attachment A ☐ 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.

   [X] 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)

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

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

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

2. Description of Emissions Unit Addressed in this Section:

Wet Cooling Tower

3. Emissions Unit Identification Number: EU003

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	January 2001	April 2002	49	[ ] Yes [X] No

9. Package Unit: Wet Cooling Tower
   Manufacturer: GEA Model Number:

10. Generator Nameplate Rating: Not Applicable

12. Emissions Unit Comment:

The cooling tower is a multi-cell recalculating wet cooling tower. Cooling will provide for the removal of reject heat from the steam cycle condenser associated with operation of the HRSG and 74 MW steam turbine.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Drift eliminators
2. Control Device or Method Code(s): 015

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: Not Applicable	
2. Maximum Production Rate: Not Applicable	
3. Maximum Heat Input Rate: Not Applicable	
4. Maximum Incineration Rate: pounds/hr Not Applicable tons/day	
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year	 7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:	

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:		2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code:	6. Stack Height:	7. Exit Diameter:
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 1_

1. Segment Description (Process/Fuel Type): Cooling Tower (emissions related to process cooling)		
2. Source Classification Code (SCC): A282001000 Process Cooling Towers	3. SCC Units: 1000 Gallons Water Circulated	
4. Maximum Hourly Rate: 3600000 gallons per hour	5. Maximum Annual Rate: $31536x10^6$ gallons per year	6. Estimated Annual Activity Factor: Not Applicable
7. Maximum % Sulfur: Negligible	8. Maximum % Ash: None	9. Million Btu per SCC Unit: Not Applicable
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

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
PM	**015**		**WP**
PM10	**015**		**WP**

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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): Not Applicable to tons/year	
6. Emission Factor:	7. Emissions Method Code:
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:	
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 __ 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:	
13. 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):	

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 _0_ of 0_

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
6. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2__ of _2

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
5. Method of Compliance:	
7. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

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:
8. 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:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

<u>Continuous Monitoring System:</u> 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:	

<u>Continuous Monitoring System:</u> 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) [X] Attached, Document ID: Appendix 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: N/A [ ] 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: None [ ] 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) [X] Attached, Document ID: Appendix C [ ] 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: ________ [ ] Previously Submitted, Date ________ [X] Not Applicable
6.	Compliance Demonstration Reports/Records [ ] Attached, Document ID: ________ Test Date(s)/Pollutant(s) Tested: ________ [ ] Previously Submitted, Date: ________ Test Date(s)/Pollutant(s) Tested: ________ [ ] To be Submitted, Date (if known): ________ Test Date(s)/Pollutant(s) Tested: ________ [X] 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

EMISSIONS UNIT INFORMATION
Section [1] of [2]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ______ ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (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: ______
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: Attachment A ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: Attachment A ☐ 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

Appendix A

PSD Permit, Title V Permit, and Acid Rain Permit Application

RECEIVED

DEC 0 7 1998

POLSKY ENERGY CORP.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an Application for Permit by:

Mr. James Shield, Vice-President
Santa Rosa Energy LLC
650 Dundee Road, Suite 150
Northbrook, Illinois 60062

DEP File No. 1130168-001AC
Permit No. PSD-FL-253
241 MW Cogeneration Facility
Santa Rosa County

Enclosed is the Final Permit Number PSD-FL-253/1130168-001 to construct a natural gas-fired 241 cogeneration facility at the Santa Rosa Energy Center, located at 5005 Sterling Way in Pace, Santa Rosa County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

P.E.
for C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-4-98 to the person(s) listed:

Mr. James Shield, SRELLC *
Mr. Craig Carson, SRELLC
Mr. Mark Cramer, P.E., R. F. Weston
Mr. Ed Middleswart, DEP-NWD
Mr. Doug Neely, EPA
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 12-4-98 (Date)

FINAL DETERMINATION
SANTA ROSA ENERGY LLC
Santa Rosa Energy Center
241 MW Cogeneration Facility

The Department distributed a public notice package on October 9, 1998 for the project to construct a natural gas-fired 241 MW Cogeneration facility. The plant proposed site is within the boundaries of the Sterling Fiber, Inc. chemical plant in Pace, Santa Rosa, County. The Public Notice of Intent to Issue was published in the Santa Rosa Press Gazette on October 26, 1998.

No comments were received by the Department from the public or the National Park Service following publication of the Notice. No substantial comments were received from EPA in its letter of November 19, 1998.

Verbal comments regarding the location of the facility in Santa Rosa County and the air quality analysis were received from Department's NE District office. Written comments were received from the applicant, Santa Rosa Energy LLC, by letter dated November 21, 1998. The applicant's comments and the Department's responses follow.

Santa Rosa Energy LLC (SRE) commented only on the draft permit and not on the Technical Evaluation and Preliminary Determination or the Draft Best Available Control Technology (BACT) Determination. The applicant's comments are keyed to the draft permit and to the Specific Conditions contained therein.

1. *Section I - Facility Description: SRE suggests that references to the steam host, Sterling Fibers, be removed since this reference may be viewed as a condition of the permit. In addition, SRE states that should the steam host be acquired or change the nature of its business, this should not affect the permit in any way.*

   The Department recognizes the applicant's concern. This description will not be changed because it is simply information describing the main user of a product (process steam). There are no conditions in the permit requiring that steam be provided to Stirling Fiber nor any that prevent selling steam to other users. If emission offsets had been used from Stirling Fibers, then there would be specific conditions limiting, for example, the amount of steam produced at Stirling Fibers.

2. *Section II - Administrative Requirements, Specific Condition 9: SRE states that the permit does not indicate a time frame under which the application for Title V Permit must be made. SRE requests that this condition be clarified to indicate that application for Title V permit is not required to be submitted until within (12) months of start up.*

   The Department will clarify this condition in accordance with Rule 62-213.420, F.A.C., Permit Applications. Specifically, Rule 62-213.420(1)(a)2. F.A.C., requires filing of a Title V application 180 days after commencing operation rather than 12 months before start up as suggested by the applicant. This rule states: " Except as provided at Rule 62-213.420(1)(a)4., a facility that commences operation as a Title V source after October 25, 1995, or that otherwise becomes subject to the permitting requirements of Chapter 62-213, F.A.C., after October 25, 1995, must file an application for an operation permit under this Chapter ninety days before expiration of the source's construction permit, but not later than 180 days after commencing operation, unless a different application due date is provided at Rule 62-204.800, F.A.C. Therefore, Specific Condition 9 of this Section II is revised as follows:

Application for Title V Permit: An application for a Title V operating permit, pursuant to ~~Chapter~~ Rule 62-213.420 (1) (a) 2. F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northwest District office (DEPNW). [Chapter 62-213, F.A.C.]

3. *Section III - Specific Condition 9: SRE requests that the 1,600 MMBtu per hour heat input be increased to a maximum heat input of 1,780 MMBtu per hour (LHV) corrected to ISO conditions. SRE states that this condition, as written, indicates that the maximum fuel consumption of the turbine is 1,600 MMBTU per hour (LHV) corrected to ISO conditions. SRE adds that while this is the heat input of a new combustion turbine operating at 100% load at ISO conditions, the restriction does not allow for performance degradation of the combustion turbine; and that it is not uncommon for fuel usage to increase more than 10% at various stages of the combustion turbine maintenance cycle.*

   The Department concurs with the applicant and the maximum heat input in this condition is revised to 1,780 MMBtu/hr (LHV) to allow for performance degradation of the combustion turbine

4. *Section III - Specific Condition No. 10: SRE indicates that the natural gas usage in the Duct burner would not exceed 3,280 x 10^6 scf on annual basis. SRE requests that this condition be changed such that the gas usage be limited to 3,280 x 10^6 scf on a twelve (12) month rolling average.*

   The Department concurs with the applicant and modified this condition as requested.

5. *Section III - Specific Condition No. 15: SRE requests that the Department clarify that the emission limits provided for in this condition are based on ISO conditions.*

   The Department modified this condition as requested. In addition, Specific Condition 9 (Turbine Capacity) allows for manufacturer's curves corrected for site conditions or equations for corrections to other ambient conditions.

6. *Section III - Specific Condition No. 20: SRE requests that the Department clarify that the maximum allowable hours of operation are 8760 hours per year.*

   This permit allows continue operation or 8760 hours per year. This condition is revised to reflect this.

7. *Section III - Specific Condition No. 27: Please clarify that any excess emissions that result from startup or shutdown of the unit are not used in calculating the 24-hour block average emissions.*

   This request is already incorporated in Specific Condition 32 which states "Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C." However, all excess emissions shall be reported in accordance with 40 CFR 60.7 as indicated in Specific Condition 29.

Miscellaneous Revisions: The Department revised some language in various permit conditions to clarify the meaning without changing the intent or the stringency of the conditions. The sulfur content in Specific Condition 20 was revised to 2 gr/100 scf since this was the limit used by Santa Rosa for its SO_2 calculations.

CONCLUSION

The Final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

PERMITTEE:

Santa Rosa Energy LLC
650 Dundee Road
Northbrook, Illinois 60062

Authorized Representative:

James Shield, Vice-President

DEP File No.	1130168-001-AC
Permit No.	PSD-FL-253
Project	241 MW Cogeneration Plant
SIC No.	4911
Expires:	December 31, 2001

PROJECT AND LOCATION:

Permit for the construction of a natural gas-fired cogeneration plant that will consist of a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent steam host; a 200 foot main stack; and ancillary equipment. The facility is designated as the Santa Rosa Energy Center and will be located within the boundary of the Sterling Fiber Chemical Plant in Pace, Santa Rosa, County.

UTM coordinates are: Zone 16; 488.970 km E and 3,381.350 km N.

STATEMENT OF BASIS:

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

ATTACHED APPENDICES MADE A PART OF THIS PERMIT:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This new major facility is a natural gas-fired 241 megawatt (MW) cogeneration plant that will consist of a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent steam host; a 200 foot main stack; and ancillary equipment. Supplemental firing will be by a duct burner rated at 585 million Btu per hour heat input.

Emissions from the combustion turbine will be controlled by Dry Low NO_X combustors, use of pipeline natural gas and good combustion while emissions from the duct burner arrangement will be controlled by Low NO_X burners, use of pipeline natural gas, and good combustion.

This Project, as presented, is exempt from the applicable requirements of Chapter 403, Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is less than 75 MW. [F.S. Chapter 403.503 (12). Definitions]

The new facility will be located on the site of the steam host, Sterling Fiber, which is a manufacturer of acrylonitrile-based fibers.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 167 Megawatt (nominal) Gas Combustion Turbine-Electrical Generator
002	Steam Generation	One 585 mmBtu/hr Duct Burner in a Supplementary Fired Heat Recovery Steam Generator (and 74 MW Steam Electrical Turbine)
003	Water Cooling	Cooling Tower

SUBSECTION C. REGULATORY CLASSIFICATION

The new facility will be classified as a Major or Title V Source of air pollution because emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) exceed 100 TPY. The new facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions will be greater than 100 TPY for CO and NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) is required for these two pollutants.

SECTION I. FACILITY INFORMATION

Given that the project constitutes a Major Facility for CO or NO_X, emissions greater than 40 TPY of sulfur dioxide (SO_2) or volatile organic compounds (VOC), 25/15 TPY of particulate matter (PM/PM_{10}), etc., also require review per the PSD rules and a BACT determination.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

PERMIT SCHEDULE

- 10/26/98 Notice of Intent published in the Santa Rosa Press Gazette.
- 10/09/98 Distributed Intent to Issue Permit.
- 09/08/98 Application deemed complete.
- 07/08/98 Received Application.

RELEVANT DOCUMENTS

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

- Application received July 8, 1998.
- Department letter dated August 3, 1998
- EPA comments received August 11, and November 19, 1998.
- Comments and additional information received from the applicant on September 8, and November 20, 1998.
- Department's Intent to Issue and Draft permit (including Draft BACT Determination and Technical Evaluation and Preliminary Determination) issued October 9, 1998.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northwest District office (DEPNW), 160 Governmental Center, Pensacola, Florida 32501-5794 and phone number 850/595-8300.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Permit Approval: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].
7. Permit Extension: *This permit expires on December 31, 2001.* The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).
8. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]

SECTION II. ADMINISTRATIVE REQUIREMENTS

9. Application for Title V Permit: An application for a Title V operating permit, pursuant to Rule 62-213.420(1)(a)2. F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northwest District office (DEPNW). [Chapter 62-213, F.A.C.]

10. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

11. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northwest District office by March 1st of each year.

12. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's Northwest District office.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

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

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

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

4. ARMS Emission Unit 001, Power Generation, consisting of a 167 megawatt combustion turbine shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 002, Steam Generation, consisting of a supplementary-fired heat recovery steam generator equipped with a 585 mmBTU/hr Duct Burner shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The modification of 40CFR60, Subpart Da promulgated on September 3, 1998 also applies to this project.

6. ARMS Emission Unit 003, Cooling Tower, is an unregulated emission unit.

7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Northwest District office.

GENERAL OPERATION REQUIREMENTS

8. Fuels: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

9. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of the fuel at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,780 million Btu per hour (mmBtu/hr). These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate, shall not exceed 585 mmBtu/hour. Natural gas usage in the Duct Burner shall not exceed 3,280 x 10^6 scf on a twelve (12 month) rolling average. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

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

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

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

15. Maximum allowable hours of operation for the 241 MW Cogeneration Plant are 8760 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine and Low NO_X burners shall be installed in the duct burner arrangement to comply with the NO_X emissions limits listed in Specific Condition 20 and 21. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. The permittee may design the heat recovery steam generator to accommodate installation of selective catalytic reduction or selective non-catalytic reduction or oxidation catalyst technologies and comply with the corresponding NO_X and CO limits listed in Specific Conditions 20, 21 and 22. [Rules 62-212.400 and 62-4.070, F.A.C.]

18. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 26. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

19. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15 % O_2. These limits or their equivalent in terms of lb/hr (ISO conditions) or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions. Each Unit shall be tested alone to comply with the applicable NSPS and as a Combined Unit to comply with the BACT limits as indicated below: [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG and Da), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	VE (%)	SO_2 (gr S/100 scf)	Comments
Combustion Turbine On Duct Burner Off	9 (24-Hr) - DLN 6 (3-Hr) - SCR	9	1.4	10	2 - (fuel)	Natural Gas Good Combustion
Combustion Turbine On Duct Burner On	9.8 (24-Hr) - DLN/Low NO_X 6 (3-Hr) - DLN/SCR 6 (3-Hr) - DLN/SNCR	24	8	10	2 - (fuel)	Natural Gas Good Combustion

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

21. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, ~~with the combustion turbine operating and the duct burner on shall not exceed 9.8 ppmvd at 15% O_2 (24-hr block average), and~~ with the combustion turbine operating and the duct burner off shall not exceed 9 ppmvd at 15% O_2 (24-hour block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed ~~106 pounds per hour (lb/hr) with the duct burner on and~~ 64.1 lb/hr with the duct burner off to be demonstrated by initial stack test. [40CFR60 Subpart GG, Subpart Da and Rule 62-212.400, F.A.C.]
- If selective catalytic or non-catalytic reduction technology is installed, the concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on or off, shall not exceed 6 ppmvd @15% O_2 on a 3-hr block average. Compliance will be determined by the continuous emission monitor (CEMS). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 71 pounds per hour (lb/hr) with the duct burner on and 42.4 lb/hr with the duct burner off to be demonstrated by initial stack test. [40CFR60 Subpart GG, Subpart Da and Rule 62-212.400, F.A.C.]
- ~~Emissions of NO_X from the duct burner shall not exceed 0.4 lb/MW-hr (gross output). [Rule 62-212.400, F.A.C. and 40CFR60 Subpart Da].~~
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither ~~24 ppm nor 75 lb/hr with the duct burner on and~~ 9 ppm nor 29 lb/hr with the duct burner off to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither ~~8 ppm nor 14 lb/hr with the duct burner on and~~ 1.4 ppm nor 2.9 lb/hr with the duct burner off to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

24. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing only pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot). Compliance this requirement with in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 45 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. [40CFR60 Subparts Da and GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

25. Particulate Matter emissions : PM/PM_{10} emissions from the *duct burner* shall not exceed 0.03 lb/mmBTU measured by Method 5 or Method 17. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. [40CFR60 Subpart Da and 62-4.070 F.A.C.]

26. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner and shall not exceed 10 percent opacity from the stack. [40CFR60 Subpart Da, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

27. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from cogeneration plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

28. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

29. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Northwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 and 21. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1997 version)].

COMPLIANCE DETERMINATION

30. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

31. Initial (I) performance tests shall be performed by the deadlines in condition 30. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of SCR or SNCR (if required). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5 or Method 17, Determination of Particulate Emissions From Stationary Sources (I, at stack only).
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG, Da. NO_X BACT limits compliance by CEMs (24-hr average or 3-hr average if SCR/SNCR is required).
    - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

32. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 29. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

33. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when

determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

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

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

36. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

37. Test Notification: The DEP's Northwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

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

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

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

MONITORING REQUIREMENTS

42. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Condition No 20 and 21, shall be reported to the DEP Northwest District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1997 version)].

43. CEMS for reporting excess emissions: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

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

45. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

   - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
   - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
   - Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

46. Determination of Process Variables:

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

47. Subpart Da Monitoring: The permittee shall comply with the applicable monitoring requirements of 40 CFR60, Subpart Da.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Santa Rosa Energy Center
Permit No. 1130168-001-AC (PSD-FL-253)
Pace, Santa Rosa County, Florida

BACKGROUND

The applicant, Santa Rosa Energy LLC (SREL), proposes to install a combined-cycle cogeneration plant at the Sterling Fibers Facility located at 5005 Sterling Way, Pace, Santa Rosa County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 167 MW, General Electric 7FA combustion turbine-electrical generator, fired exclusively with pipeline natural gas. The project includes a supplementary-fired heat recovery steam generator (HRSG) and a steam turbine-electrical generator to produce an additional 74 MW of electrical power. A portion of the steam produced will be at the host Sterling Fibers Plant. The unit will exhaust through a 200 foot stack. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated October 7, 1998, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on July 8, 1998 and included a proposed BACT proposal prepared by the applicant's consultant, Roy F. Weston. Additional information amending the application and BACT proposal was received on September 8.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E., and Teresa Heron, Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas Combustion Controls	0.0051 lb/MMBtu (CT) 0.0080 lb/MMBtu (DB)
Volatile Organic Compounds	As Above	1.4 ppm (CT) 0.0190 lb/MMBtu (DB)
Carbon Monoxide	As Above	9 ppm (CT) 0.080 lb/MMBtu (DB)
Nitrogen Oxides	Dry Low NO_X Combustors Dry Low NO_X Burners	9 ppm @ 15% O_2 (CT) 0.08 lb/mmBtu (DB)

According to the revised application, the units, would emit approximately 402 tons per year (TPY) of NO_X, 260 TPY of CO, 45 TPY of VOC, 7 TPY of SO_2, and 55 TPY of PM/PM_{10}.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by SERL is consistent with Subpart GG NSPS which allows NO_X emissions of approximately 110 ppm for the high efficiency unit to be purchased by the Santa Rosa Energy LLC.

The fired duct burner required for supplementary gas-firing of the HRSG is subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The BACT proposed by SERL is consistent with the key historically applicable NSPS requirement of 0.20 pounds of NO_X per million Btu heat input (lb NO_X/mmBtu). It is well below the revised Subpart Da output-based limit of 1.6 lb NO_X/MW-hr promulgated on September 3, 1998.

No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on recent limitations set by EPA and the States for comparable stationary gas turbine.

Project Location	Power Output and Duty	NO_X Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Lakeland, FL	350 MW CC CON	9/9/7.5 - NG 42/15/15 - No. 2 FO	DLN/HSCR/SCR WI/HSCR/SCR	230 MW WH 501G CT Initially 250 MW simple cycle and 25 ppm NO_X limit on gas
Mid-GA Cogen	308 MW CC CON	9 - NG 20 - No. 2 FO	DLN & SCR	2x119 MW WH 501D5A CTs
Fort Myers, **FL**	1500 MW CC CON	9 - NG	DLN	6x170 MW **GE MS 7241** CTs Draft Permit, Non-BACT
Tiger Bay, FL	270 MW CC CON	15/10 - NG 42 - No. 2 FO	DLN &/or SCR WI	184 MW GE MS7001**FA** CT DLN/15 ppm or SCR/10 ppm
Hines Polk, **FL**	485 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW WH 501FC CTs Canceled GE CTs
Tallahassee, FL	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231FA CT DLN guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC CON	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW WH 501**F** CTs
Sithe/IPP, NY	1012 MW CC CON	4.5 - NG	DLN & SCR	4 x160 MW GE 7**FA** CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW GE 7**FA** CTs
Barry, AL	800 MW CC CON	3.5 - NG (CT/DB)	DLN & SCR	3x170 MW GE 7**FA** CTs

CC = Combined Cycle
DB = Duct Burner
NG = Natural Gas
CT = Combustion Turbine
CON = Continuous
HSCR = Hot SCR
FO = Fuel Oil
ISO = 59°F
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
LPG = Liquefied Propane Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari
ppm = parts per million

Factors in Common with Santa Rosa Energy LLC Project are bolded.

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Mid-GA Cogen,	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
Fort Myers, FL	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Tiger Bay, FL	0.045 lb/mmBtu-NG 0.053 lb/mmBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Barry, AL	0.034 lb/mmBtu - NG/CT 0.057 lb/mmBtu - CT/DB	0.015 lb/mmBtu After CT and DB	0.011 lb/mmBtu - CT/DB 10% Opacity	Gas Only Good Combustion

The following table is a sample of information on recent NO_X limitation by EPA and the States for combined cycle and cogeneration projects incorporating supplementary-firing in heat recovery steam generators.

Project Location	Duct Burner Rated Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu or ppm)	Technology	Comments
Plant Berry, AL	159	0.018 mmBtu/hr	DLN, SCR	3x170 MW GE 7FA CTs 3 Duct Burners
Saranac Energy, NY	553	0.08 lb/mmBtu	SCR	2 GE 7EA CTs with DBs Permit issued 1992
Bermuda HEL, VA	197	9 ppm	Steam Injection, SCR	1175 mmBtu/hr CT (1992)
Bear Island Paper, VA	129	9 ppm	SCR	474 mmBtu/hr CT (1992)
Pilgrim Energy, NY	214	4.5 ppm (CT) 0.012 lb/mmBtu (DB)	Steam Injection, SCR Low NO_X Burner, SCR	2 WH 501D5 CTs 2 Duct Burners
Selkirk Cogen, NY	206	9 ppm (CT) 0.018 lb/mmBtu (DB)	Low NO_X Burner, SCR	1173 mmBtu/hr CT
Grays Ferry, PA	366	9 ppm (CT) 0.09 lb/mmBtu (DB)	DLN Low NO_X Burner	WH 501D5A CT with DB DLN Failed, SCR Required

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Letter from EPA Region IV dated August 11, 1998
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

COMBUSTION TURBINE AND DUCT BURNER CONTROL TECHNOLOGIES:

The applicant presented an analyses of the different available control technologies for all of the pollutants subject to PSD review and a BACT determination. The applicability of these measures is best understood in conduction with the mechanisms by the pollutants are generated.

Nitrogen Oxides Formation

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in lean, near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the SREL project because only natural gas will be used.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

The potential for NO_X emissions from gas-fired duct burners is lower than from gas turbines because of the lower temperature and pressure. In a supplementary-fired duct burner, the gas to the HRSG is raised from approximately 1100 to less than 1800 °F. Thermal NO_X formation essentially ceases at temperatures below 2000 °F.[1] Since the fuel contains virtually no nitrogen, there is little potential for fuel NO_X formation either.

NO_X Control Techniques

Combustion Controls

The excess air in lean combustion, cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

The emission characteristics of General Electric's DLN 2 combustors are given in Figure 2. NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity. GE has since further upgraded its combustors and this description is not precise for its more advanced DLN-2.6.

Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the SREL project are shown in Figure 3. The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle to achieve 9 ppm of NO_X and 9 ppm of CO at somewhat less than 50 percent load. Presumably the emission characteristics of the DLN-2.6 are similar are similar to the DLN 2, except that the combustor emits NO_X at concentrations of 9 ppm (instead of the 25 ppm shown in Figure 2) at loads between 50 and 100 percent. Because of the "totally pre-mixed" design, emissions at less than 50 percent load are probably also lower for the DLN 2.6 than the DLN-2.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, results in a lower achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to the steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle), such as the F class. As in the case of wet injection, higher CO and hydrocarbon emissions can occur as a result of employing combustion controls to minimize NO_X.

Figure 5 is a diagram of a typical in-line duct burner configuration and individual burner manufactured by Coen, one of the potential providers of this equipment. The unit will reside within the duct between the combustion turbine outlet and the HRSG. The oxygen-rich, hot turbine exhaust is used to burn natural gas introduced through the burner arrangement. In contrast to the pre-mixing that can be accomplished in the combustion turbine, not much (other than design optimization) can be done regarding the manner by which the very large volume of hot combustion air and the fuel are mixed prior to combustion. Basically the burners are described as Low NO_X burners.

There have been reports of lower emissions (on a lb/mmBtu or ppm basis rather than on a lb/hr basis) with the duct burners on. It has been theorized that the results are "suspect" and may have been cause by the "inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.".[2] It has also been theorized that transformations between NO and NO_2, interfere with the test method.[3] As previously mentioned, since the duct burner operates at a lower temperature and pressure than the gas turbine, it is possible that concentrations may actually be lower with the duct burner on.

<u>Selective Catalytic Combustion</u>

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas. As of early 1992, over 100 gas turbine installations already used SCR in the United States. No combustion turbines in Florida employ SCR. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

In a manner analogous to balancing control of NO_X from the combustor with emissions of CO and hydrocarbon, similar balancing is required when controlling NO_X by SCR. Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit BACT limits as low as 3.5 ppm NO_X have been specified using SCR for an F Class project (with small in-line duct burners) in Alabama and proposed for another F Class project in Mississippi.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. A supplementary-fired unit (such as the SREL project) is defined as an HRSG fired to an average temperature not exceeding about 1800 °F. The 585 mmBtu/hr duct burner described by SREL will achieve temperatures close to this value. Although no SNCR applications are known, the technology appears to be feasible and possibly less complicated than SCR.

Carbon Monoxide (CO) Control

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 Berkshire, Massachusetts facility, 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppm at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the CT value of 9 ppm baseload proposed by SREL appears relatively low, but consistent with the capabilities of DLN-2.6 technology as discussed above. This proposed limits are achievable through good combustion practice. When simultaneously operating the combustion turbine and the duct burner, CO concentrations emissions will be less than 24 ppm which is within the range of limits set for combustion turbines operating alone. Annual emissions of CO are expected to be less than 260 tons per year (combustion turbine and duct burner).

Volatile Organic Compound (VOC) Control

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC for both the turbine and the duct burner. The CT proposed limit is 1.4 ppm . According to GE, even lower VOC emissions were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[4] VOC concentrations will be less than 8 ppm for simultaneous operation of the combustion turbine and duct burner.

Particulate Matter (PM/PM_{10}) Control

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas will be the only fuels fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. This has been chosen as BACT by the applicant, the Department concurs. Annual emissions of PM/PM_{10} are expected to be less than 55 tons per year (combustion turbine and duct burner).

Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required.

BACKGROUND ON SELECTED GAS TURBINE AND DUCT BURNER

SERL plans to the purchase a 167 MW (nominal) General Electric 7FA combined cycle gas turbine with a supplementary-fired heat recovery steam generator (HRSG) equipped with a duct burner and a steam turbine-electrical generator to produce an additional 74 MW (nominal) of electrical power and process steam.

The 585 mmBtu/hr duct burner will be manufactured by Coen or equivalent and will be a low NO_X design. For reference, the heat rate of a combustion turbine with a 600 mmBtu/hr supplementary-fired duct burner used to make only electrical power is 4,350 Btu/KW-hr.[5] In cogeneration mode, if only 50 percent of the process steam generated is considered, the heat rate is even lower. This compares with the presumed heat rate of 10,667 Btu/KW-hr in the recently revised NSPS Subpart Da.[6]

The first commercial GE 7F Class unit was installed at the Virginia Power Chesterfield Station in 1990.[7] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppm These actually achieve less 25 ppm of NO_X and 15 ppm of CO. The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppm of NO_X, the City obtained a performance guarantee from GE of 9 ppm.[10] FPL also obtained a guarantee of 9 ppm for six GE 7241FA turbines to be installed at the Fort Myers Repowering project. These limits were incorporated in the draft permit issued for the project.[11]

General Electric, other manufacturers, and their customers are relying on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[12]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7FA units met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.[13] Although the permitted limit is 15 ppm, GE has already achieved emission levels of approximately 6 ppm on gas at a dual-fuel 7EA (120 MW combined cycle) unit at Cane Island Power Park in Kissimmee, FL.[14] The Cane Island unit is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line and performance guarantees less than 9 ppm can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[15]

The 9 ppm NO_X limit on natural gas during baseload requested by SREL is typical compared with recent BACT determinations for F Class units, such as those previously listed.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V Control System, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V Control System.[16]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the SERL project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 and 21.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	1.4 ppm (CT on, DB off) 8 ppm (CT and DB on))
CO	As Above	9 ppm (CT on, DB off) 24 ppm (CT and DB on)
NO_X (CT on, DB off)	DLN or SCR	9 ppm or 6 ppm
NO_X (CT and DB on)	DLN and Low NO_X, or SNCR, or SCR	9.8 ppm, or 6 ppm, or 6 ppm DB limited to 0.4 lb/MW-hr

RATIONALE FOR DEPARTMENT'S DETERMINATION

- SERL can obtain a guarantee from GE for DLN-2.6 combustors which have been demonstrated to meet all of the above limits on 7FA Class gas turbine with the duct burner off.
- The turbine emission limits with the duct burner off comply with the NSPS and are less than or equal to recent Department BACT determinations applicable to new units at start-up.
- VOC emissions of 1.4 ppm from the combustion turbine proposed by SERL are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels

with the DLN-2.6 combustors while firing natural gas. The limit of 8 ppm with the duct burner on is also quite low.

- The duct burner used for supplementary firing will comply with the NSPS (Subpart Da). It will cause sligthly higher NO_X concentrations than permitted for the combustion turbine alone.
- If a different combustion turbine is selected or if the NO_X limits cannot be met with Low NO_X technology with the duct burner on, SERL must install either SNCR or SCR technology and meet correspondingly lower emission limits achievable by the latter technologies.
- The levelized costs of NO_X reduction to 3.5 - 6 ppm by conventional SCR installed in the HRSG were estimated by SERL as $4,660 - 5,247 per ton of NO_X removed after initial control by DLN to 9 ppm. The Department's estimates the levelized costs at $2,500 per ton of NO_X removed starting with DLN combustion control to 25 ppm. This figure does not reflect a possible credit for savings by purchasing the less expensive line of combustors such as the GE DLN-1 or DLN-2 in lieu of the DLN 2.6 combustors. Neither the Department nor the SERL estimates reflect the cost-effectiveness of duct burner-generated NO_X removal.
- If the combined unit can meet applicable limits by DLN with the duct burner off but not with the duct burner on, SNCR can be utilized when the duct burner is on. SNCR is less expensive and more cost-effective than SCR. It can be turned off when the duct burner is off since the proper operating temperature range will not exist under that mode.
- SCR and SNCR cause environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. At equal emission rates, DLN technology is a better control strategy than SCR or SNCR. At higher emission rates, DLN can still be justified as BACT given the negative effects of SCR described above. Accordingly, the Department has set a range of emission limits and control methods based on the turbine and duct burner combustion technologies chosen by SREL.
- The Department's overall BACT determination is equivalent to approximately 0.16 lb/MW-hr by DLN/Low NO_X or 0.10 lb/MW-hr by SCR or SNCR. For reference, NSPS promulgated on September 3, 1998 requires that new Da units meet a limit of 1.6 lb/MW-hr.
- The Department considers a limit of 9.8 ppm (DLN and Low NO_X) or 6 ppm (SCR or SNCR) as BACT for this cogeneration facility. In addition the contribution of the duct burner to overall emissions cannot exceed 0.4 lb/MW-hr.
- The CO concentrations of 9 ppm are very low with the duct burner off. With the duct burner on, they will be less than 24 ppm which is within the range of recent Department BACT determinations for combustion turbines alone. The Department will set CO limits achievable by good combustion equal to 9 ppm for the combustion turbine and 24 ppm when the duct burner is on. For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppm on gas while the limit for the FPL Fort Myers project is 12 ppm. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- SREL evaluated the use of an oxidation catalyst designed for 85 percent reduction and having a three year catalyst life. The oxidation catalyst control system was estimated by SREL to increase

the total capital cost of the project by $1,462,846, with an annualized cost of $548,257 per year. SREL estimated levelized costs for CO catalyst control at about $2,481 per ton to control CO emissions to 39 TPY (from 260 TPY).

- The VOC emission concentration of 1.4 ppm proposed by SREL is at the lower end of values determined as BACT for the combustion turbine alone. Good Combustion is sufficient to achieve these low levels. With the duct burenr on, the levels are still relatively low except at very high operating rates.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, and the FPL Fort Myers projects in Florida as well as the Barry, Alabama project.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 29 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: For 1 hour following a shutdown less than or equal to 8 hours.
Warm Start: For 2 hours following a shutdown between 8 and 48 hours.
Cold Start: For 4 hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the unit has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[17]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

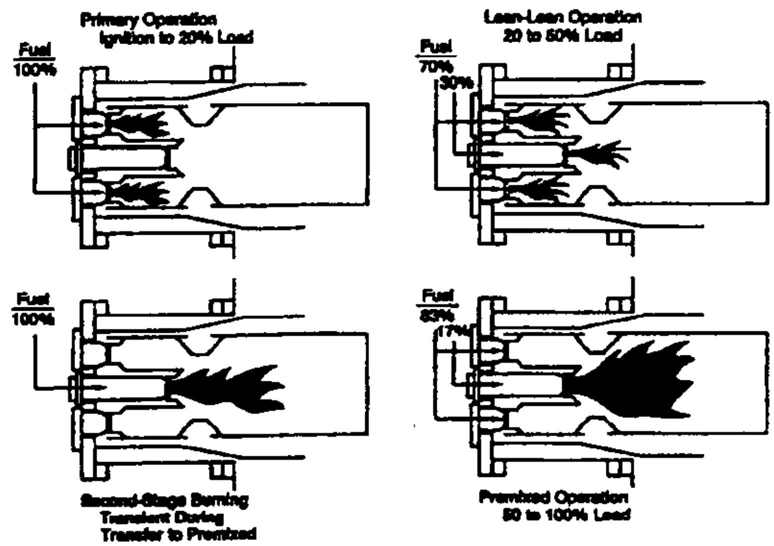
DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
P.E.	
for C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
12/2/98 Date:	12-4-98 Date:

References

1 Report. EPA. "Summary Report - Control of NO_X Emissions by Reburning." Document EPA/625/R-96/001. February, 1996.
2 Letter. Harper, J. A., EPA Region IV to Fancy, C., Florida DEP. June 3, 1994. Construction Permit Amendment for Orlando Cogen Limited, L.P.
3 Verbal Communication. Harley, M., Florida DEP, and Linero, A. A., Florida DEP. September 18, 1998. Custom Fuel Monitoring and NSPS Da and Db Applicability.
4 Telecon. Vandervort, C., GE, and Linero, A. A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."
5 Fisk, R.W. and VanHousen, R. L., GE. "Cogeneration Application Considerations." 1996.
6 Report. EPA. "New Source Performance Standards, Subparts Da and Db - Summary of Public Comments and Responses." Document EPA-453/R-98-005
7 Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.
8 Davis, L.B., GE. "Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines." 1994.
9 Florida DEP. PSD Permit, City of Tallahassee Purdom Unit 8. May, 1998.
10 City of Tallahassee. PSD/Site Certification Application. April, 1997.
11 Florida DEP. Intent to Issue Permit. FPL Fort Myers Repowering Project. September, 1998.
12 State of Alabama. PSD Permit, Alabama Power/Barry Sithe/IPP (GE 7FA).
13 Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program
14 Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.
15 Telecon. Schorr, M., GE, and Linero, A. A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.
16 Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."
17 General Electric. Combined Cycle Startup Curves. June 19, 1998.



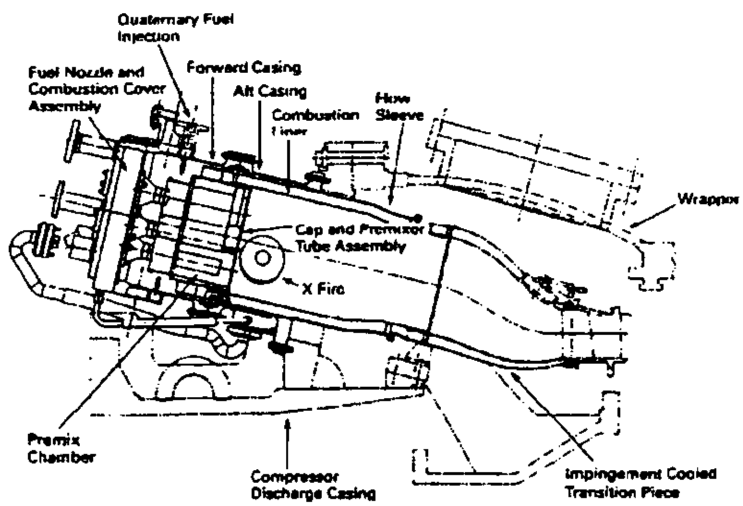


Figure 1 - Dry Low NOX Operating Modes - DLN-1

Cross Section of DLN-2.0

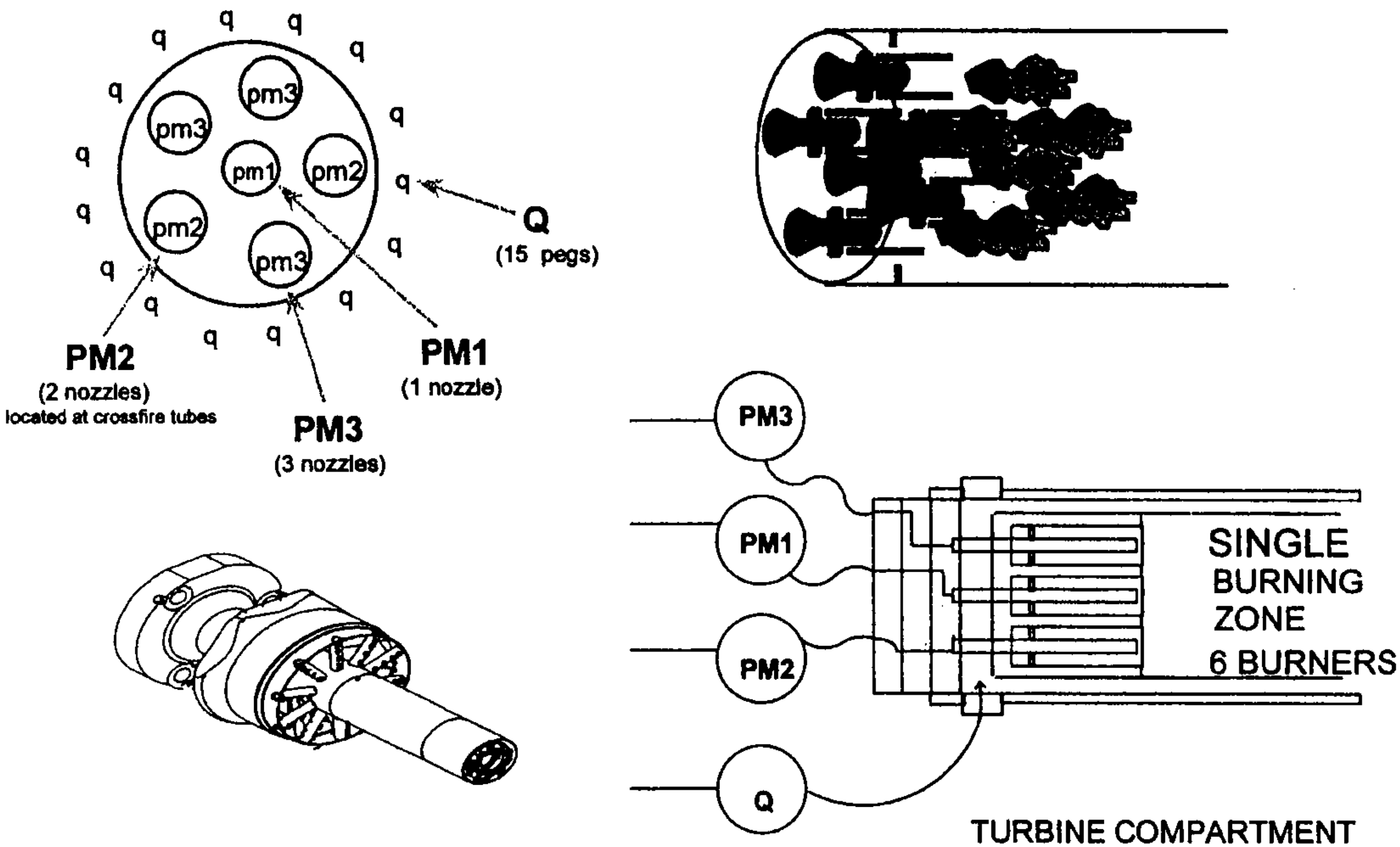


Figure 2 - GE DLN-2.6 Combustor and Nozzle Arrangement

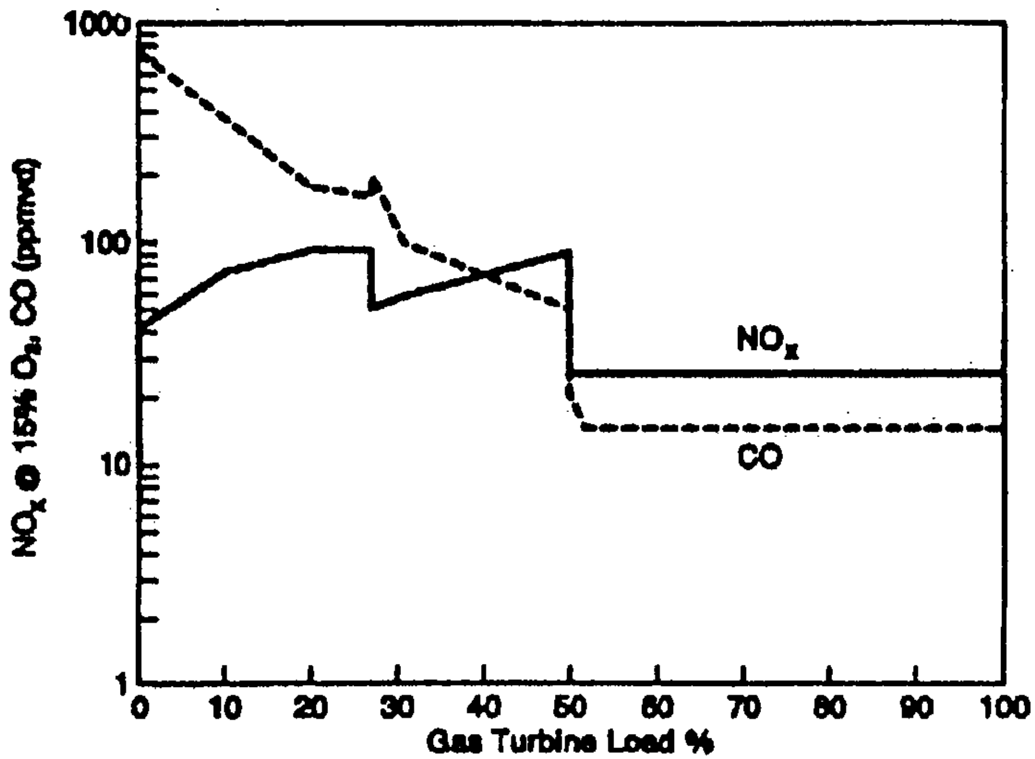


Figure 3 - Emissions Performance Curves for GE DLN-2 Combustors

Firing Natural gas in Dual Fuel GE 7FA Combustion Turbine

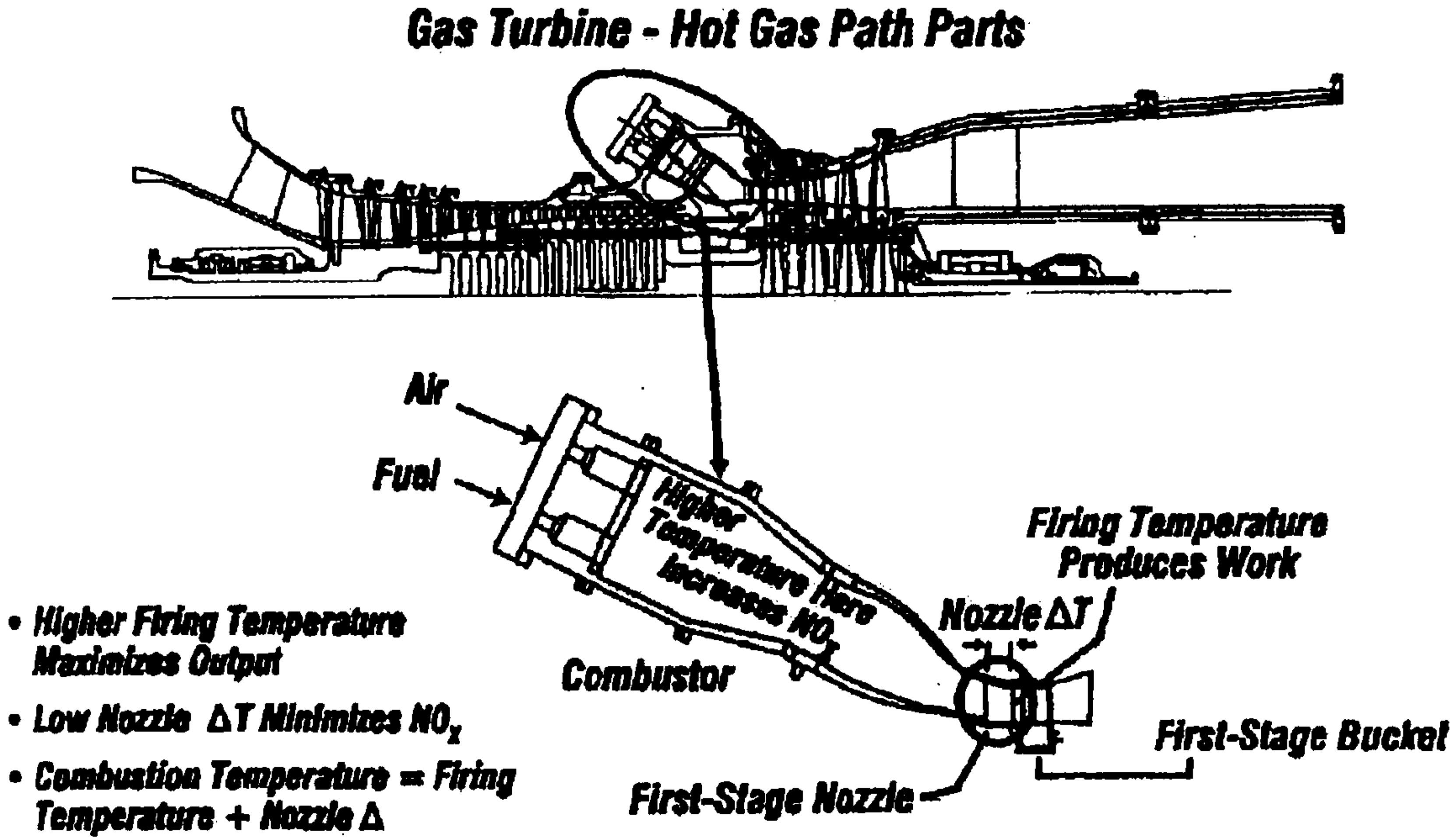


Figure 4 - Relation Between Flame Temperature and Firing Temperature

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

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

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

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

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

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

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

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

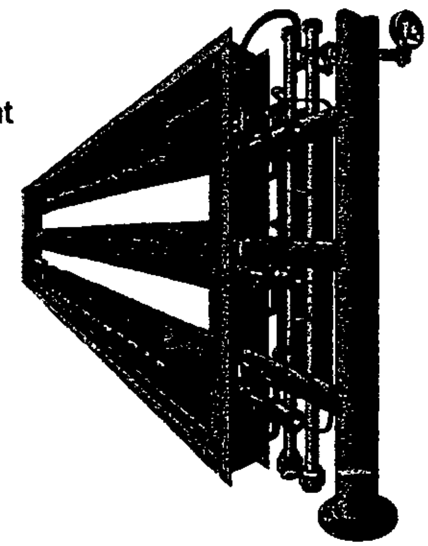
b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports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

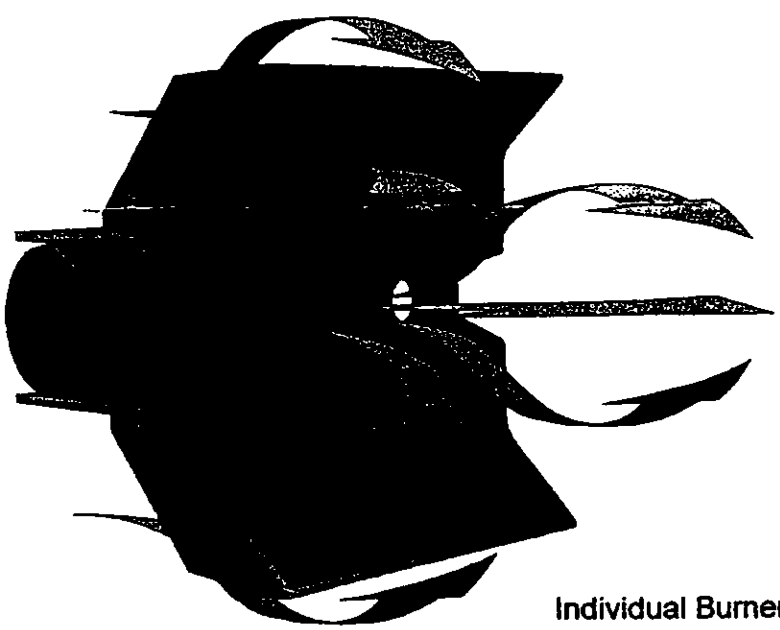
c) Records of monitoring information shall include:

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

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

Burner Arrangment





Individual Burner

Figure 5 - Coen In-Line Gas-Fired Duct Burner

Santa Rosa Energy, LLC
Santa Rosa Energy Center
Facility ID No. **1130168**
Santa Rosa County

Initial Title V Air Operation Permit
FINAL Permit No. **1130168-004-AV**

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

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority:
Department of Environmental Protection
Northwest District

160 Governmental Center
Pensacola, Florida 32501-5794

Telephone: 850/595-8300
Fax: 813/595-4417

Initial Title V Air Operation Permit
FINAL Permit No. **1130168-004-AV**

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

Permittee:
Santa Rosa Energy, LLC

FINAL Permit No. 1130168-004-AV
Facility ID No. 1130168
SIC Nos.: 49, 4911
Project: Initial Title V Air Operation Permit

This permit is for the operation of the Santa Rosa Energy Center. This facility is located southwest of Sterling Fibers, Inc., within the plant boundary at 5001 Sterling Way, Pace, Santa Rosa County; UTM Coordinates: Zone 16, 488.974 km East and 3381.526 km North; and, Latitude: 30° 33' 58.3" North, and Longitude: 87° 06' 54.1" West.

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

Referenced attachments made a part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix TV-4, Title V Conditions, version dated 02/12/02
Appendix SS-1, STACK SAMPLING FACILITIES, version dated 10/07/96
TABLE 297.310-1, CALIBRATION SCHEDULE, version dated 10/07/96
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT, version dated 07/96
Appendix CP-1, Compliance Plan dated April 1, 2002
Acid Rain Phase II Part Application signed by the Designated Representative on January 14, 2000.

Effective Date: January 1, 2003
Renewal Application Due Date: July 1, 2007
Expiration Date: December 31, 2007

Department of Environmental Protection

for Howard L. Rhodes, Director
Division of Air Resource Management

HLR/tbc

Section I. Facility Information.

Subsection A. Facility Description.

This is a new facility located on the site of the steam host, Sterling Fiber, which is a manufacturer of acrylonitrile-based fibers. It is a cogeneration plant and consists of one natural gas-fired nominal 167 megawatt (MW) General Electric (Frame 7F design), combined-cycle, combustion turbine-electrical generator with a Heat Recovery Steam Generator (HRSG), one 200-foot exhaust stack, an unregulated wet cooling tower, and a small natural gas preheater (dew point heater). The combustion turbine unit is equipped with a Dry Low NO_X (DLN) combustor. Emissions from the combustion turbine are also controlled by the use of pipeline natural gas and good combustion techniques. Drift eliminators are installed on the cooling tower to reduce PM/PM_{10} emissions.

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

Based on the initial Title V permit application received April 1, 2002, this facility is *not* a major source of hazardous air pollutants (HAPs).

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

E.U. ID No.	Brief Description
-001	One nominal 167 Megawatt Gas Combined-Cycle Combustion Turbine-Electrical Generator with Heat Recovery Steam Generator (HRSG).

Unregulated Emissions Units and/or Activities

-003	Wet Cooling Tower.

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

Subsection C. Relevant Documents.

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

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

These documents are on file with permitting authority:
Initial Title V Permit Application received April 1, 2002.
Letters from the applicant received July 26, 2002, and August 19, 2002, offering comments on the DRAFT Title V Permit. The first letter includes the approved Custom Fuel Monitoring Plan.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. Appendix TV-4, Title V Conditions, is a part of this permit.
{Permitting note: Appendix TV-4, Title V Conditions, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

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

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

and,
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

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

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

7. Compliance Plan. Based on the application, (an) emissions unit(s) (was/were) not in compliance. Appendix CP-1, Compliance Plan, is a part of this permit.
[Rule 62-213.440(2), F.A.C.]

8. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
[Rule 62-296.320(1)(a), F.A.C.]

9. **Not federally enforceable.** Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include all necessary actions to prevent fugitive dust.
[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the initial Title V permit application received April 1, 2002]

{Note: This condition implements the requirements of Rules 62-296.320(4)(c)1., 3., & 4., F.A.C. (see Condition 57. of Appendix TV-4, Title V Conditions.)}

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

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

12. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Northwest District Office.

Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8300
Fax: 850/595-4417

[1130168-001-AC, Specific Condition 7.]

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

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155, Fax: 404/562-9164

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

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	One nominal 167 Megawatt Gas Combined-Cycle Combustion Turbine-Electrical Generator.

This emissions unit consist of one natural gas fired nominal 167 megawatt (MW) General Electric (Frame 7F design) combined-cycle combustion turbine-electrical generator with a Spray Inlet Temperature Suppression (SPRITS) system, and one 200-foot exhaust stack. The unit is equipped with a Dry Low NO_X (DLN) combustor. A Continuous Emissions Monitor (CEM) monitors NO_X for the combustion turbine.

{Permitting note: This emissions unit is regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C., Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT), and Air Construction Permit 1130168-001-AC (PSD-FL-253).}

Compliance Assurance Monitoring (CAM) *does not apply* to this emissions unit.

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

<u>**General**</u>

A.1. <u>Definitions.</u> For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60 shall apply, except that the term "Administrator" when used in 40 CFR 60 shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; and Rule 62-204.800(7)(a), F.A.C.]

A.2. <u>Concealment.</u> No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

A.3. <u>Circumvention.</u> The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.
[Rule 62-210.650, F.A.C.; and 1130168-001-AC, Specific Condition 14.]

<u>**Essential Potential to Emit (PTE) Parameters**</u>

A.4. <u>Turbine Capacity.</u> The maximum heat input rate, based on the lower heating value (LHV) of the fuel at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,780 million Btu per hour (mmBtu/hr). This maximum

heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and 1130168-001-AC, Specific Condition 9.]

A.5. Methods of Operation -- Fuel. Only pipeline natural gas shall be fired in this unit.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and 1130168-001-AC, Specific Condition 8.]

A.6. Hours of Operation. Maximum allowable hours of operation for the Cogeneration Plant are 8760 hours per year.
[Rules 62-4.160(2), 62-210.200(PTE), and 62-212.400, F.A.C.; and 1130168-001-AC, Specific Condition 15.]

Control Technology

A.7. A Dry Low NO_X (DLN) combustor is used on the stationary combustion turbine to comply with the NO_X emissions limits listed in Specific Conditions **A.9.** and **A.10.**
[Rules 62-4.070 and 62-212.400, F.A.C.; and 1130168-001-AC, Specific Condition 16.]

A.8. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN system. The DLN system shall be tuned to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices.
[Rules 62-4.070 and 62-210.650, F.A.C.; and 1130168-001-AC, Specific Condition 19.]

Emission Limitations and Standards

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

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **A.9.** through **A.14.** are based on the specified averaging time of the applicable test method.}

A.9. The following table is a summary of the BACT determination, and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2. These limits or their equivalent in terms of lb/hr (ISO conditions) or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions.

Operational Mode	NOx (ppmvd)	CO (ppmvd)	VE (% opacity)	SO_2 (gr S per 100 scf)	Comments
Combustion turbine on DLN	9 (24-hr)	9 (29 lb/hr)	10	2 (fuel)	Pipeline Natural Gas Good Combustion

[Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.; and 1130168-001-AC, Specific Condition 20.]

A.10. Nitrogen Oxides (NO_X) Emissions.

- The concentration of NO_X in the stack exhaust gas with the combustion turbine operating shall not exceed 9 ppmvd at 15% O_2 (24-hour block average).
- When NO_X monitoring data are not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

[40 CFR 60 Subpart GG; Rule 62-212.400, F.A.C.; and 1130168-001-AC, Specific Condition 21.]

A.11. Carbon Monoxide (CO) Emissions. Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither 9 ppmvd nor 29 lb/hr to be demonstrated by stack test using EPA Method 10.
[Rule 62-212.400, F.A.C.; and 1130168-001-AC, Specific Condition 22.]

A.12. [Reserved.]

A.13. Sulfur Dioxide (SO_2) Emissions. SO_2 emissions shall be limited by firing only pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic feet). Compliance with this requirement, in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition **A.34.**, will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the combustion turbine.
[40CFR60 Subpart GG; Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C; 1130168-001-AC, Specific Condition 24.; and Applicant Request.]

A.14. Visible Emissions (VE). VE emissions shall serve as a surrogate for PM/PM_{10} emissions, and shall not exceed 10% opacity from the stack.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.; and 1130168-001-AC, Specific Condition 26.]

Excess Emissions

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

A.15. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall

be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during either "cold start-up" to, or shutdowns from, cogeneration plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined-cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined-cycle operation following a complete shutdown lasting at least 48 hours.
[G.E. Combined-Cycle Startup Curves Data; Rules 62-210.700(1) and (2), F.A.C.; and 1130168-001-AC, Specific Condition 27.]

A.16. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.
[Rule 62-210.700(4), F.A.C.; and 1130168-001-AC, Specific Condition 28.]

A.17. Excess Emissions Report. If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify the Department's Northwest District Office within one working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Conditions No. **A.9.** and **A.10.**
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7; and 1130168-001-AC, Specific Condition 29.]

Test Methods and Procedures

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

A.18. Compliance with the allowable emission limiting standards shall be determined *annually* by using the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.
[1130168-001-AC, Specific Condition 30.]

A.19. *Annual* compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

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

[1130168-001-AC, Specific Condition 31.]

A.20. Continuous compliance with the NO_X emission limits. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by Rule 62-210.700, F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Specific Condition **A.17.**
[Rules 62-4.070 and 62-210.700, F.A.C.; 40 CFR 75; and 1130168-001-AC, Specific Condition 32.]

A.21. Compliance with the SO_2 and PM/PM_{10} emission limits. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e).
[1130168-001-AC, Specific Condition 33.]

A.22. Compliance with CO emission limit. *Annual* compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the *annual* RATA testing for the NO_X CEMS required pursuant to 40 CFR 75.
[1130168-001-AC, Specific Condition 34.]

A.23. [Reserved.]

A.24. Testing procedures. Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.
[1130168-001-AC, Specific Condition 36.]

A.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.26. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

A.27. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

TABLE 297.310-1
CALIBRATION SCHEDULE

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

A.28. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.; and 1130168-001-AC, Specific Condition 46.]

A.29.1. The permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.29.2. The permittee shall design the emission units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions **A.9.** through **A.11.**
[Rules 62-4.070 and 62-204.800, F.A.C.; and 1130168-001-AC, Specific Condition 18.]

A.30. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62-210.300(4), F.A.C.

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

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; SIP approved; and 1130168-001-AC, Specific Condition 38.]

Monitoring of Operations

Continuous Monitoring Requirements

A.31. Continuous Monitoring System. The permittee shall calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this unit. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions **A.9.** and **A.10.**, shall be reported to the Department's Northwest District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile within one working day).
[Rules 62-204.800, 62-210.700, 62-4.130, and 62-4.160(8), F.A.C.; 40 CFR 60.7; and 1130168-001-AC, Specific Condition 42.].

A.32. CEMS for reporting excess emissions. Subject to EPA approval, the NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Upon a request from the Department, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[1130168-001-AC, Specific Condition 43.]

A.33. Continuous Monitoring System Reports. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.
[1130168-001-AC, Specific Condition 44.]

A.34. Natural Gas Monitoring Schedule. A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30. (The Phase II Acid Rain Permit Application for the facility was deemed complete on February 7, 2000. See Section IV, Acid Rain Part, of this permit.)
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 2 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

[1130168-001-AC, Specific Condition 45.]

Training Requirements

A.35. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment.
[Rule 62-4.070(3), F.A.C.; and 1130168-001-AC, Specific Condition 13.]

Recordkeeping and Reporting Requirements

A.36. Test Notification. The Department's Northwest District Office shall be notified, in writing, at least 15 days before the annual compliance test(s).
[1130168-001-AC, Specific Condition 37.]

A.37. Test Results. Compliance test results shall be submitted to the Department's Northwest District Office no later than 45 days after completion of the last test run.
[Rule 62-297.310(8), F.A.C.; and 1130168-001-AC, Specific Condition 39.]

A.38. Records. All measurements, records, and other data required by this permit shall be recorded in a permanent form and retained for at least **five (5)** years following the date on which

such measurements, records, or data are recorded. These records shall be made available to the Department upon request.
[1130168-001-AC, Specific Condition 40.]

A.39. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

A40. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.; and 1130168-001-AC, Specific Condition 41.]

Section IV. Acid Rain Part.

Santa Rosa Energy Center

ORIS code: 55242

The emissions unit listed below is regulated under Phase II of the Federal Acid Rain Program.

E.U. ID No.	Description
-001	One nominal 167 Megawatt Gas Combined-Cycle Combustion Turbine-Electrical Generator.

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

a. DEP Form No. 62-210.900(1)(a), version 07/01/95, signed by the Designated Representative on January 14, 2000, and deemed complete by the Department on February 7, 2000.

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

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

E.U. ID No.	EPA ID #	Year	2003	2004	2005	2006	2007
-001	COG 01	SO_2 allowances to be determined by U.S. EPA.	0	0	0	0	0

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

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

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

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

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

4. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.

[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

Appendix H-1. Permit History/ID Number Changes.

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Revised Date(s)
-001	Combined-Cycle Combustion Turbine	1130168-001-AC (PSD-FL-253) 1130168-002-AC 1130168-003-AC	12/04/98 5/25/00 4/01/02	12/31/01	7/1/02

Appendix I-1. List of Insignificant Emissions Units and/or Activities.

Santa Rosa Energy, LLC
Santa Rosa Energy Center

FINAL Permit No. **1130168-004-AV**
Facility ID No. **1130168**

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

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

Brief Description of Emissions Units and/or Activities:

1. Operation of a 2.6 mmBtu/hr fuel gas heater.
2. Operation of lubricating and hydraulic oil container vents.
3. Operation of vacuum pumps for sample collection.
4. Operation of parts cleaners using non-hazardous solvents.
5. Storage of water treatment chemicals.
6. Water treatment tasks (e.g., reverse osmosis, demineralization, pH control, addition of anti-corrosion and anti-scaling agents, and oil-water separation).
7. Maintenance of grounds and lawns.

{Note: Emissions units or activities which are added to a Title V source after issuance of this permit shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit, and also qualify for exemption from permitting pursuant to Rule 62-213, F.A.C. [Rule 62-213.430(6)(a)]}

Appendix U-1. List of Unregulated Emissions Units and/or Activities.

Santa Rosa Energy, LLC
Santa Rosa Energy Center

FINAL Permit No. **1130168-004-AV**
Facility ID No. **1130168**

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
-003	Wet Cooling Tower.

Table 1-1. Summary of Air Pollutant Standards and Terms.

Santa Rosa Energy, LLC
Santa Rosa Energy Center

Permit No.: 1130168-004-AV
Facility ID No.: 1130168

These tables summarize information for convenience purposes only, and do not supersede any of the terms or conditions of this permit.

E.U. ID Nos.	Brief Description	
-001	Combined-Cycle Combustion Turbine	Maximum allowable hours of operation for the gas turbine are 8760 hours per year.

		Allowable Emissions		Equivalent Emissions*			
Pollutant	Fuel	Standard(s)	lbs./hour	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
Visible Emissions	gas	10% Opacity				1130168-001-AC	A.14.
Carbon Monoxide	gas	9 ppmvd	29		127	1130168-001-AC	A.11.
Sulfur Dioxide	gas	2 grains of sulfur/dscf	5		12.7	1130168-001-AC	A.13.
Nitrogen Oxides	gas	9 ppmvd	64.1		280.75	1130168-001-AC	A.10.

Notes:
*The "Equivalent Emissions" listed are for informational purposes only.

Table 2-1. Summary of Compliance Requirements.

Pollutant	Fuels	Compliance Method	Testing Time Frequency		CMS*	See permit condition(s)
Visible Emissions	gas	EPA Method 9	Annual			A.19.
Carbon Monoxide	gas	EPA Method 10	Annual			A.19.
Sulfur Dioxide	gas	Fuel sampling and analysis	Daily			A.21.
Nitrogen Oxides	gas	CMS*	Continuous		Yes	A.20.

Notes:
*CMS [=] continuous monitoring system

Appendix CP-1. Compliance Plan.

Santa Rosa Energy, LLC
Santa Rosa Energy Center

FINAL Permit No. **1130168-004-AV**
Facility ID No. **1130168**

- In accordance with air construction permit 1130168-001-AC (PSD-FL-253), compliance and CEMS certification testing shall be completed prior to June 30, 2002. Construction shall be completed and compliance testing shall be initiated by July 1, 2002 (this corresponds to the extended expiration date of air construction permit 1130168-001-AC). Authority to construct shall not be extended beyond this expiration date without further authorization.

- Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the units, and annually thereafter as indicated in air construction permit 1130168-001-AC.

[1130168-001-AC, Specific Condition 30.]

- The permittee shall submit a properly signed certification document from the permittee's Professional Engineer stating that:

  1. The construction of the emissions units was completed in accordance with air construction permit 1130168-001-AC, and

  2. The emissions units have been tested, and compliance with the terms and conditions of air construction permit 1130168-001-AC has been properly demonstrated within 45 days after completion of all of the initial performance tests.

[Rules 62-212.400(7)(b), 62-213.440(2), and 62-213.420(1)(a)5., F.A.C.; 1130168-001-AC, Specific Condition 39; and Title V Permit Application received April 1, 2002]

Phase II Permit Application

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

This submission is: New ☒ ☐ Revised

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

Plant Name	State	ORIS Code
Santa Rosa Energy Center	FL	55242

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

a Boiler ID#	Compliance Plan b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Compliance Plan c Repowering Plan	d New Units Commence Operation Date	e New Units Monitor Certification Deadline
COG01	Yes		1 Sept 2001	1 Jan 2002
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

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

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

Santa Rosa Energy Center

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Recordkeeping and Reporting Requirements (cont.)

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

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

Liability.

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

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

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

Certification

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

David Plauck	
[signature]	1/14/2000

STEP 5 (optional)
Enter the source AIRS and FINDS identification numbers, if known

EPA United States Environmental Protection Agency

CAMD BUSINESS SYSTEM

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REVIEW YOUR FACILITY AND UNIT DETAILS

Santa Rosa Energy Center, FL (ORISPL 55242)

The current Representative information for this facility is displayed below. To access a list of previous Representatives for this facility, click the Previous Representatives button.

General | Units | Owners/Operators | **Representatives** | Contacts | Programs | Agency Staff

Current Representatives

Program	Representative Type	Representative Name	Effective Date
ARP	Primary	Ronald Rose	07/02/2002
ARP	Alternate	Jason M Goodwin	04/02/2007
CAIRNOX	Primary	Ronald Rose	04/02/2007
CAIRNOX	Alternate	Jason M Goodwin	04/02/2007
CAIROS	Primary	Ronald Rose	04/02/2007
CAIROS	Alternate	Jason M Goodwin	04/02/2007
CAIRSO2	Primary	Ronald Rose	04/02/2007
CAIRSO2	Alternate	Jason M Goodwin	04/02/2007

Previous Representatives | Back

Representative Information

Jason M Goodwin
Calpine Corporation
Director - EHS (Eastern Region)
717 Texas Avenue
Suite 1000

Ronald Rose
Calpine Operating Services Company, Inc.
1003 Papermill Road
Mobile, AL 36610
Phone: (251) 330-1031 x 104

Houston, TX 77002	Fax: (251) 330-1093
Phone: (713) 570-4795	Email: rrose@calpine.com
Fax: (713) 332-5168	
Email: jason.goodwin@calpine.com	

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

NOTICE OF ADMINISTRATIVE PERMIT CORRECTION

In the Matter of an Application for an Administrative Permit Correction by:

Mr. Donald B. Walters Regional Power Vice President, Southeast Calpine Corporation Island Center 2701 N. Rocky Point Drive Suite 1200 Tampa, FL 33607	FINAL Title V Permit No. **1130168-004-AV** Administrative Permit Correction No. **1130168-005-AV** **Santa Rosa Energy Center**

Based on a request and information provided in a letter from the Calpine Corporation received on July 10, 2003, the Department has determined that an Administrative Permit Correction to information contained in FINAL Permit No. **1130168-004-AV** is required. The correction changes the permit owner's name from **Santa Rosa Energy, LLC**, to **Calpine Corporation**. This correction is minor in nature and does not alter, modify, or revise any permit requirement. This Administrative Permit Correction was processed as project No. **1130168-005-AV**, pursuant to Rule 62-210.360, F.A.C.

This permit administrative correction corrects and is a part of FINAL Permit No. **1130168-004-AV**, and is issued pursuant to Chapter 403, Florida Statutes.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF ADMINISTRATIVE PERMIT CORRECTION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/21/03 to the person(s) listed or as otherwise noted:

Mr. Donald B. Walters, Calpine Corporation*
Ms. Heidi Whidden, Calpine Corporation
Ms. Sandra Veazey, Northwest District Office
U.S.EPA, Region 4 (INTERNET E-mail Memorandum)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday 7/21/03
(Clerk) (Date)

September 7, 2005

Mr. Benjamin M. H. Borsch, P.E.
Manager, Safety Health & Environment
Calpine Corporation
2701 N. Rocky Point, Suite 1200
Tampa, Florida 33607

Re: PSD-FL-253 Permit Modification, Annual Testing Requirements
DEP File Number 1130168-006-AC
Santa Rosa Energy Center / Santa Rosa County

The applicant, Calpine Corporation, applied on July 19, 2005, to the Department for a change to the annual testing requirements. The request was to void annual testing requirements in the event that the facility operates for less than 400 hours per year. Natural gas is the sole fuel permitted for use at this facility.

The Department has reviewed the modification request. The referenced PSD permit is hereby modified as follows:

III. Emissions Unit(s) Specific Conditions
Compliance Determination:

31. Initial (I) performance tests shall be performed by the deadlines in condition 30. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of SCR or SNCR (if required). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. <u>In the event that the facility does not combust natural gas for greater than 400 hours during the fiscal year, the requirement for annual compliance tests shall be waived.</u> The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- *EPA Reference Method 5 or Method 17, "Determination of Particulate Emissions From Stationary Sources" (I, at stack only).*
- *EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).*
- *EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).*
- *EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG, Da. NO_X BACT limits compliance by CEMs (24-hr average or 3-hr average if SCR/SNCR is required).*

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

All other terms and conditions of this permit remain unchanged. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

____
Michael G. Cooke, Director
Division of Air Resource
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PSD Permit Modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ____________ to the person(s) listed:

Benjamin M. H. Borsch, P.E. *
Heidi M. Whidden, Calpine Corporation
Sandra Veazey, FDEP NWD
Gregg Worley, EPA
John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

____________________ ______________
(Clerk) (Date)

SGS

October 17, 2005

CALPINE CORPORATION
HOG BAYOU ENERGY CENTER
1003 Papermill Road
Mobile, AL 36610

CERTIFICATE OF ANALYSIS

RE:	SUBMITTED SAMPLE
PRODUCT:	SAID TO BE NATURAL GAS
SUBMITTED BY:	CALPINE CORPORATION on 10/14/05
SAMPLE MARKS:	HOG BAYOU ENERGY CENTER; SREC DTD 08/08/05
OUR REF:	08-7851

COMPONENTS, MOLE %

TEST	RESULTS
METHANE	96.281
ETHANE	2.0047
PROPANE	0.38707
I-BUTANE	0.09259
N-BUTANE	0.08425
NEO-PENTANE	ND
I-PENTANE	0.02913
N-PENTANE	0.01939
N-HEXANES	ND
N-HEPTANES	ND
N-OCTANES	ND
N-NONANES	ND
N-DECANES	ND
HENDECANES	ND
DODECANES	ND
TRIDECANES	ND
TETRADECANES	ND
HYDROGEN	ND
NITROGEN	0.44733
OXYGEN	0.01902
ARGON	ND
CARBON DIOXIDE	0.63517
CARBON MONOXIDE	ND
WATER	ND
HYDROGEN SULFIDE, ppm	0.9
TOTAL SULFUR, ppm	0.9

SGS

CALPINE CORPORATION
HOG BAYOU ENERGY CENTER
1003 Papermill Road
Mobile, AL 36610

CERTIFICATE OF ANALYSIS 08-7851 (continued)

CALCULATED PROPERTIES	RESULTS
RELATIVE DENSITY	0.5803
HEATING VALUE, BTU/cf, GROSS, 14.73 psia, 60 deg. F	
SATURATED	1010
HIGHER HEATING VALUE (DRY)	1028
LOWER HEATING VALUE (NET)	926

ND = NOT DETECTED

Methods

Hydrocarbons – ASTM D-1945
Sulfur – ASTM D-5504
Relative Density – ASTM D-3588
Heating Values – ASTM D-3588

/S/: Stephanie A. Richards, Senior Chemist
SGS NORTH AMERICA INC.
MINERALS SERVICES DIVISION

SAR/rf

SGS North America Inc. | Minerals Services Division
1212 North 39th Street, Suite 323, Tampa, FL 33609 t (813) 248-6566 f (813) 247-2562 www.sgs.com
Member of SGS Group (Société Générale de Surveillance)

SGS

TERMS AND CONDITIONS

By accepting, using or relying upon information and documents (reports, certificates) from SGS North America Inc., the client for whom this information was developed and documents are issued, and any person who relies upon this information and documents, agrees to the following terms and conditions, except as otherwise agreed to in writing by SGS:

1) Any use by the client of this information/document is contingent upon the timely payment of all fees, and is subject to the terms of engagement.

2) Client agrees that SGS does not, either by entering into this contract or by performing the services rendered, assume, abridge, abrogate or undertake to discharge any duty or responsibility of client or any other person.

3) SGS warrants that it will perform its services in a workmanlike manner. SGS makes no further warranty of any kind, expressed or implied.

4) In consideration for performing the services rendered at the fee charged, SGS expressly limits its professional liability to all persons accepting, using or relying upon this information and documents to ten times the amount of the fee paid, or $25,000, whichever is less.

5) SGS expressly disclaims liability as an insurer or guarantor. If any person relying upon this information and documents desires protection from loss or damage, appropriate insurance should be obtained.

6) Acceptance, use and reliance upon this information and document shall be governed by the laws of the state where services were rendered.

7) No report shall be reproduced except in full, without the written approval of the Laboratory.

8) Invoices not paid within thirty days will be subject to an interest charge of 1.5% per month, or the maximum rate allowed by law, plus all other collection costs, including attorney fees.

SGS North America Inc. | Minerals Services Division
1212 North 39th Street, Suite 323, Tampa, FL 33609 t (813) 248-6566 f (813) 247-2562 www.sgs.com
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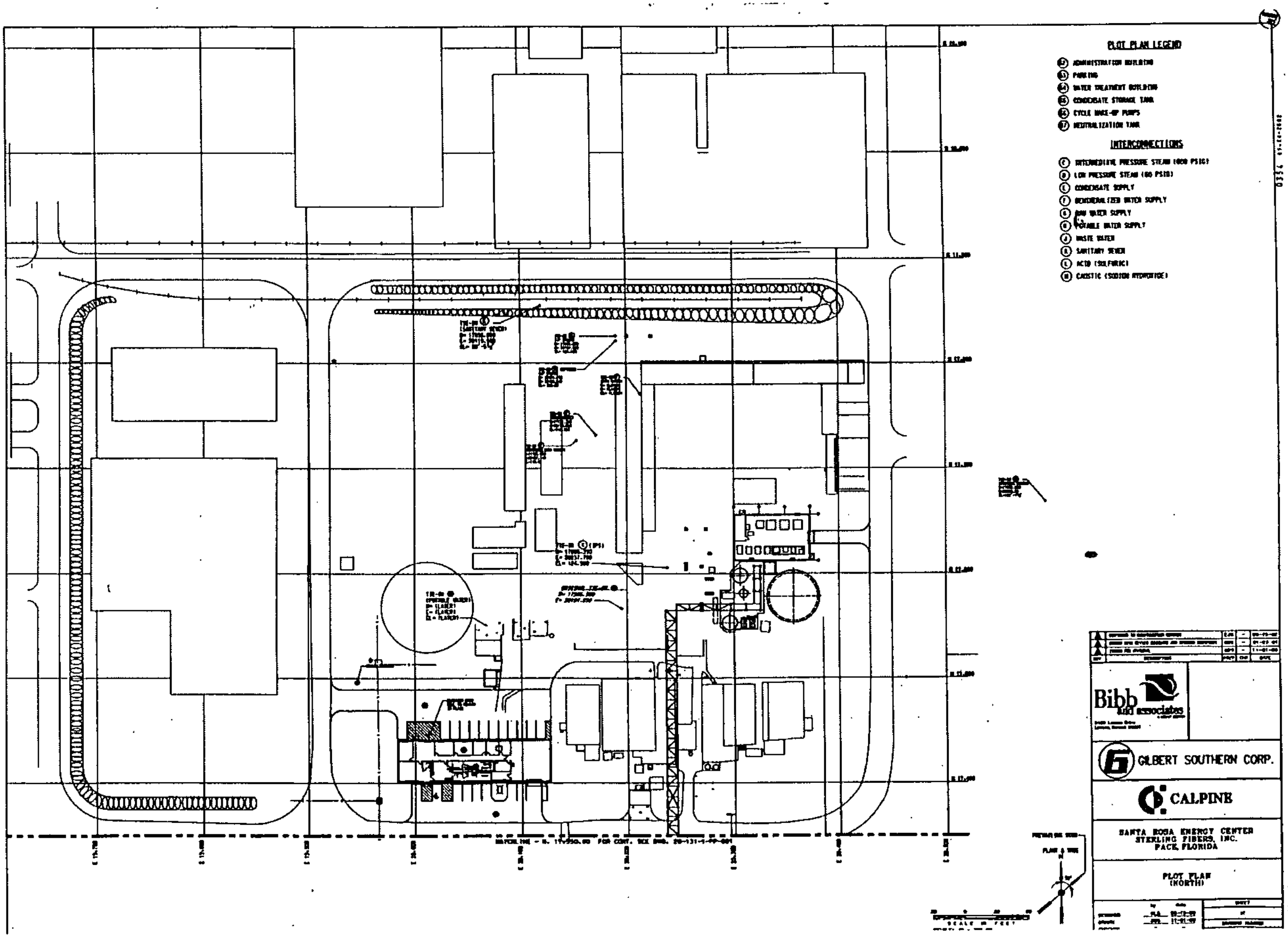
Appendix B

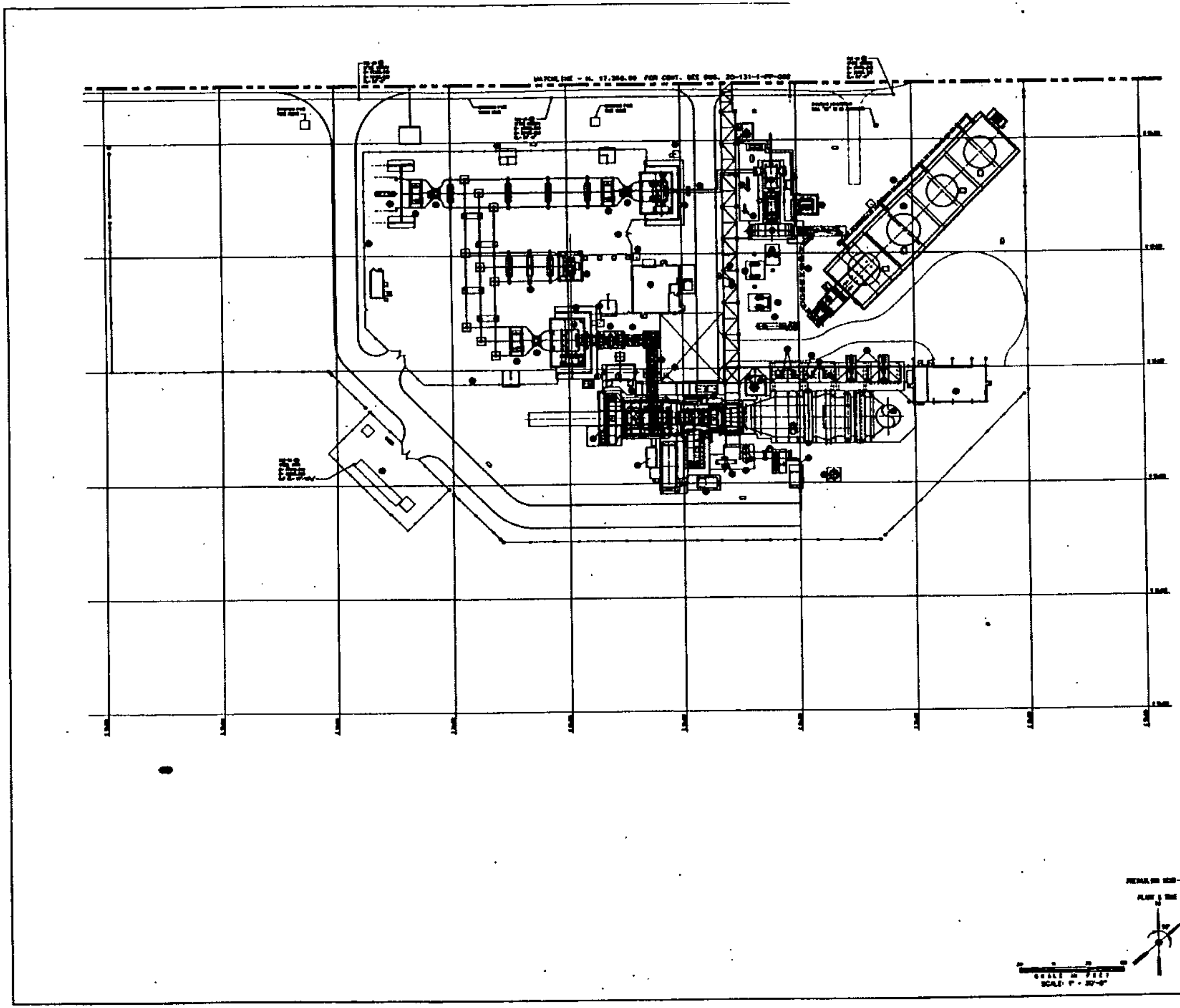
Figures

FACILITY LOCATION MAP
SANTA ROSA ENERGY CENTER
PACE, SANTA ROSA COUNTY, FLORIDA

Sources: USGS Quad Map of Pace & Milton S., Fl., 1987, PR 1987; ECT, 2007.



PLOT PLAN LEGEND
ADMINISTRATION BUILDING
PARKING
WATER TREATMENT BUILDING
CONDENSATE STORAGE TANK
CYCLE MAKE-UP PUMPS
NEUTRALIZATION TANK
INTERCONNECTIONS
INTERMEDIATE PRESSURE STEAM
LOW PRESSURE STEAM
CONDENSATE SUPPLY
DEMINERALIZED WATER SUPPLY
RAW WATER SUPPLY
POTABLE WATER SUPPLY
WASTE WATER
SANITARY SEWER
ACID (SULFURIC)
CAUSTIC (SODIUM HYDROXIDE)
Bibb and associates
GILBERT SOUTHERN CORP.
CALPINE
SANTA ROSA ENERGY CENTER
STERLING FIBERS, INC.
PACE, FLORIDA
PLOT PLAN
(NORTH)



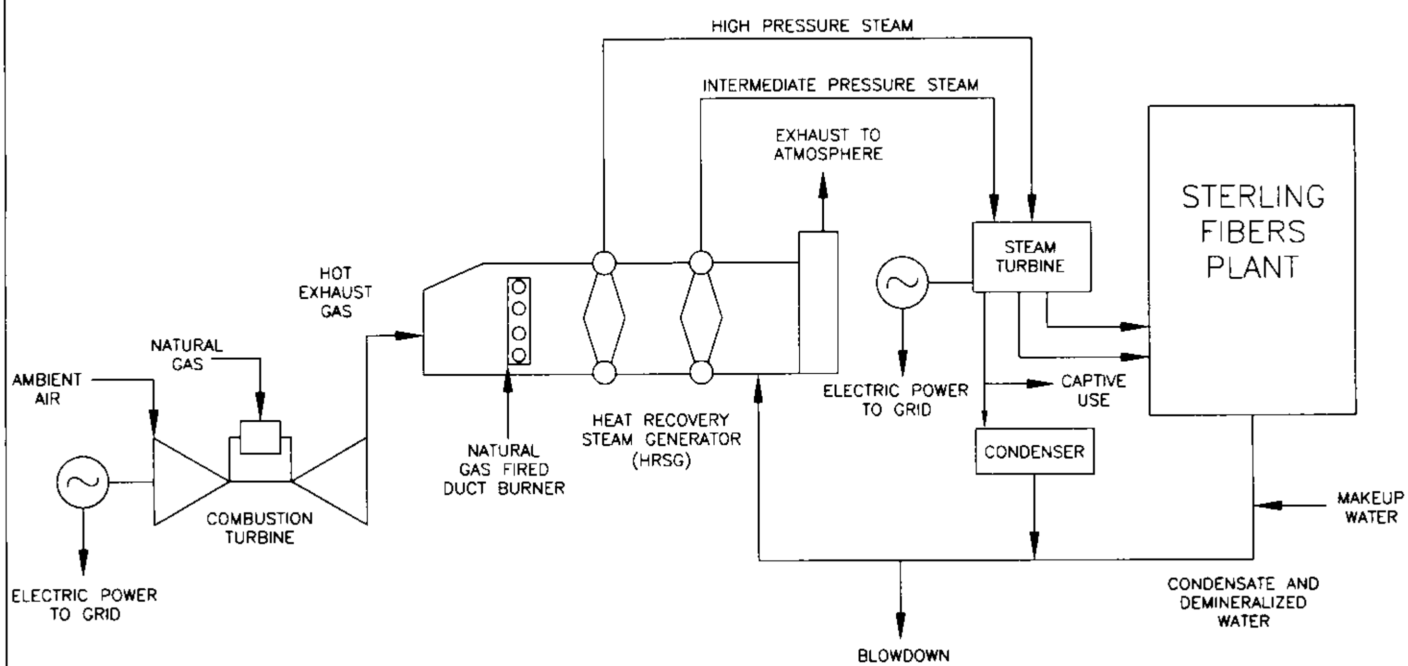
Bibb and associates

GILBERT SOUTHERN CORP.

CALPINE

SANTA ROSA ENERGY CENTER
STERLING FIBERS, INC.
PACE, FLORIDA

PLOT PLAN
(SOUTH)



SIMPLIFIED PROCESS DIAGRAM
SANTA ROSA ENERGY CENTER
PACE, SANTA ROSA COUNTY, FLORIDA

Source: ECT, 2007.

Appendix C

Procedures

APPENDIX C

OPERATIONS AND MAINTENANCE PROCEDURES

Operations and maintenance of the GE7FA combustion turbine (CT) is consistent with normal manufacturer and industry standards. The site maintains historical records of operations and maintenance activities.

PROCEDURES FOR STARTUP AND SHUTDOWN COMBUSTION TURBINE (CT) AND HEAT RECOVERY STEAM GENERATOR (HRSG)

STARTING SEQUENCE

Startup of the General Electric 7FA combustion turbine (CT) is implemented by means of a computer controlled startup sequencer. The startup sequencer is given a START command by the control room operator. The startup sequencer then controls startup up to synchronous speed. The control room operator then issues the command for the generator to synchronize to the power grid. The control room operator then monitors & manages the plant start up & all environmental aspects of turbine start up.

Operation of the cooling tower may be started either before or after operation of the turbine has started. The cooling tower is started by first opening the circulating water bypass valve, then starting one of the two circulating water pumps. Cooling tower fans are started at low speed as required to respond to the plant heat demand and operating conditions. All required steps are initiated from the control room.

SHUTDOWN SEQUENCE

CT shutdown occurs in a similar fashion as the startup. Shutdown of the General Electric 7FA combustion turbine (CT) is implemented by means of a computer controlled shutdown sequencer following gradual reduction of plant output. The turbine's shutdown sequencer is given a STOP command by the control room operator. The shutdown sequencer then further reduces CT load, disconnects the CT from the power grid (opens the generator breaker), allows the CT to cool for three (3) minutes in a controlled manner and then closes the fuel supply. Once the CT has cooled sufficiently it is allowed to coast down and will automatically go on turning gear.

Cooling tower shutdown reverses the cooling tower start up sequence.

Appendix D

HAP Emissions Calculations and Fuel Analysis

Santa Rosa Energy Center
Santa Rosa Energy, LLC
Calpine Eastern Corporation

Hazardous Air Pollutants
Potential Emissions

Substance	Natural Gas	Units	Source[1]	Emissions: (lb/hr) NG	Emissions: (tpy)[2]
1,3-Butadiene	4.30E-07	lb/MMBtu	AP-42	8.20E-04	3.59E-03
2-Methylnaphthalene					
3-Methylchloranthrene					
7,12-Dimethylbenz(a)anthracene					
Acenaphthene					
Acenaphthylene					
Acetaldehyde	4.00E-05	lb/MMBtu	AP-42	7.63E-02	3.34E-01
Acrolein	6.40E-06	lb/MMBtu	AP-42	1.22E-02	5.35E-02
Anthracene					
Benzene	1.20E-05	lb/MMBtu	AP-42	2.29E-02	1.00E-01
Benz(a)anthracene					
Benzo(a)pyrene					
Benzo(b)fluoranthene					
Benzo(g,h,i)perylene					
Benzo(k)fluoranthene					
Chrysene					
Dibenz(a,h)anthracene					
Dichlorobenzene					
Ethylbenzene	3.20E-05	lb/MMBtu	AP-42	6.11E-02	2.67E-01
Fluoranthene					
Fluorene					
Formaldehyde 3	1.07E-04	lb/MMBtu	CARB	2.04E-01	8.94E-01
Hexane					
Indeno(1,2,3-cd)pyrene					
Naphthalene	1.30E-06	lb/MMBtu	AP-42	2.48E-03	1.09E-02
PAH	2.20E-06	lb/MMBtu	AP-42	4.20E-03	1.84E-02
Phenanthrene					
Propylene Oxide	2.90E-05	lb/MMBtu	AP-42	5.53E-02	2.42E-01
Pyrene					
Toluene	1.30E-04	lb/MMBtu	AP-42	2.48E-01	1.09E+00
Xylene (Total)	6.40E-05	lb/MMBtu	AP-42	1.22E-01	5.35E-01
Hazardous Air Polluant Total, Per Unit				**8.10E-01**	**3.55E+00**

1. Emission factors for natural-gas fired turbines taken from AP-42 Section 3.1, *Stationary Gas Turbines*, April 2000, Tables 3.1-3,4,5
2. Combustion turbine emissions in tpy are based on the maximum lb/hr emissions at 8,760 hours per year of operation
3. Formaldehyde emission factor obtained from California Air Resources Board (CARB) per Heidi Whidden of Calpine.

Appendix E

List of Insignificant Activities

APPENDIX E

LIST OF INSIGNIFICANT ACTIVITIES

In addition to the designated emissions units, the Facility operates equipment or work practices which produce insignificant emissions below the deminimus threshold. These are listed here:

- 2.6 MMBtu/hr Fuel Gas Heater
- Lubricating and Hydraulic Oil Container Vents
- Vacuum Pumps for Sample Collection
- Parts Cleaners using non-hazardous solvents
- Water treatment chemical storage
- Water treatment (reverse osmosis, demineralization, pH control, addition of anti-corrosion and anti-scaling agents, oil water separation)
- Grounds and Lawn Maintenance

Appendix F

Applicable Regulations

REGULATORY APPLICABILITY SCREEN - FEDERAL

Facility: Santa Rosa Energy Center, Pace, FL.

Regulation	Applies?	Applicability Criteria (Yes, No, P = Partially, U = Unknown)	Status/ Discussion
40 CFR 51, Appendix S Federal New Source Review Program: Non-Attainment Area New Source Review (11/29/05 latest rev)	No	Applies to construction, reconstruction or modification of a control equipment or other air emission source at a facility located in a non-attainment area (one or more NAAQS are exceeded) or in attainment or unclassifiable area for ozone that is located in an ozone transport region if the facility is a major source under the NANSR regulation and the state SIP does not contain an approved Part D pre-construction review regulation. Facilities are considered major source if they have a PTE ≥ 100 tpy CO, PM-10, TSP, or SO2, 25 tpy NOx or VOC or 10 tpy lead.	Although SREC has a PTE that would make it a major source of air pollutants, it is located in a attainment area for all criteria pollutants. In addition, the FL SIP contains a Part D NSR pre-construction review regulation. Therefore, this regulation will not apply to the facility as long as the area where it is located continues to be classified as attainment area and the FL SIP contains an approved Part D pre-construction review regulation.
40 CFR 52, Section 52.21 Federal New Source Review Program: Prevention of Significant Deterioration (Attainment Areas) (11/29/05)	No	Applies to construction, reconstruction or modification of a control equipment or other air emission source at a facility located in an attainment area (none of the NAAQS are exceeded) if the facility is a major source under the PSD regulation. Facilities listed in 40 CFR 52.21(b)(1)(i)(a) are considered major sources if they have a PTE ≥ 100 tpy of any regulated air contaminant. All other facilities are major sources if their PTE is ≥ 250 tpy of any regulated air contaminant.	As mentioned above, the SREC facility is a major source of CO, PM-10/TSP, NOx, SO2, and VOC emissions and is located in an attainment area for all criteria pollutants. However, the FL SIP has a Part C PSD pre-construction review regulation. Therefore, this regulation will not apply to the facility as long as the FL SIP contains an approved PSD pre-construction review regulation.
40 CFR 60, Subpart A Standards of Performance for New Stationary Sources, General Provisions (06/01/06)	Yes	Applies to facilities which contain a stationary source subject to a New Source Performance Standard and includes general monitoring, testing, and notification requirements.. Although there are NSPS for over 60 types of sources, this applicability analysis will only cover the types of sources present at the facility, which include gas turbines, auxiliary boiler, duct burners, and oil storage tanks.	SREC has the following units subject to a NSPS standard: one combustion turbines (NSPS Subpart GG).
40 CFR 60, Subpart D, Da, Db, Dc Standards of Performance for Fossil Fuel Fired Steam Generators. (10/17/00)	No	Applies to fossil-fuel fired steam generating units	The HRSG at SREC is unfired (no duct burners), No portions of Subpart D apply.
40 CFR 60, Subpart K, Ka, Kb	No	Applies to storage vessels storing petroleum liquids.	SREC does not have any regulated petroleum storage tanks. No portions of Subpart K apply.

Regulation	Applies?	Applicability Criteria (Yes, No, P = Partially, U = Unknown)	Status/ Discussion
Standards of Performance for Storage Vessels for Petroleum Liquids			
40 CFR 60, Subpart GG Standards of Performance for Stationary Gas Turbines (7/8/04)	Yes	Applies to stationary gas turbines with a heat input ≥ 10.7 Gjoules/hour (10 MMBtu/hr) based on lower heating value of fuel. Construction or modification after 10/3/77.	SREC has one stationary gas turbine subject to this regulation.
40 CFR 61, Subpart A National Emission Standards for Hazardous Air Pollutants, General Provisions (12/13/05)	No	Applies to facilities which contain a stationary source subject to a National Emission Standard for Hazardous Air Pollutants. The HAPs addressed by Part 61 are asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride.	SREC does not have any type of operation or emission source regulated by Part 61 and therefore, is presently not subject to any Part 61 NESHAP.
40 CFR 63 National Emission Standards for Hazardous Air Pollutants for Source Categories.	No	Applies to facilities subject to a National Emission Standard for Hazardous Air Pollutants for Source Categories. Although there are several source categories covered by NESHAPs, this applicability analysis will only cover the types of source categories present at the facility, which include gas turbines, auxiliary boiler, duct burners, oil storage tanks, cooling tower, RICE (diesel generator), oil/water separator, and cold degreaser.	SREC is a minor source of HAPs and therefore the NESHAPs discussed below will not apply as long as the facility retains its minor source status..
40 CFR 63, Subpart Q National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers (4/9/04)	No	Applies to new and existing industrial process cooling towers which are either major sources of HAPs or located in facilities which are major sources of HAPs.	SREC is a minor source of HAPs. In addition, SREC does not use any chromium-based water treatment chemical in its cooling tower.
40 CFR 63, Subpart YYYY	No	Applies to new or reconstructed stationary combustion turbines that began construction/reconstruction after 1/14/03, and located at a major	Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. The

Regulation	Applies?	Applicability Criteria (Yes, No, P = Partially, U = Unknown)	Status/ Discussion
National Emission Standards for Stationary Combustion Turbines (8/18/04)		source of HAPs. New or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine must only comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register. Duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart.	stationary turbines at the SREC facility began construction prior to 1/14/03 and are located in a minor source of HAPs. Therefore, they are not subject to this NESHAP.
40 CFR 64 Compliance Assurance Monitoring (CAM) (10/22/97)	No	Applies to facilities that are subject to the Title V Operating Permit Regulation and contain sources which are subject to an emission limit or standard excluding the exemptions listed in 40 CFR 64.2(b), use a control device to achieve compliance with any applicable standard, and have a pre-control emissions or PTE equal to or greater than the major source threshold. Major source thresholds are: 100 tpy of CO, TSP, PM-10, and SO2; 25 tpy of NOx, VOC, and combination of HAPs; 10 tpy single HAP and lead.	The gas turbine at SREC is subject to NSPS Subpart GG NOx standards, have a NOx emission limit specified in the permit, and uses Low NOx Burners to comply with the NOx emission limit. Because the facility Title V Permit specifies a continuous compliance determination method for the turbine NOx emissions, SREC is exempt under 40CFR64.2(b)(1)(vi) from any additional monitoring requirements and can use their NOx CEMS to satisfy the CAM rule requirements.
40 CFR 70 State Operating Permit Programs (12/19/05)	Yes	Applies to any major source of regulated air pollutants, any source subject to a NSPS or NESHAP standard, or any source subject to the Acid Rain regulations. There are certain exemptions to NSPS and NESHAP sources.	SREC is a major source of regulated air pollutants, is subject to NSPS standards, and is subject to the Acid Rain regulations. However, the FL SIP also has an approved Title V Permit regulation. Therefore, this regulation will not apply directly to the facility as long as the SIP contains an approved Title V Permit regulation.
40 CFR 72 - 78 Acid Rain Program Regulations (05/18/05)	Yes	Applies to a unit listed in Tables 1, 2, or 3 of 40 CFR 73.10(a), new utility unit serving a generator with a nameplate capacity ≥ 25 MWe, cogeneration units which lose their exemption status under 40 CFR 72.4(b)(4), qualifying facilities which lose their exemption status under 40 CFR 72.4 (b)(5), and IPP facilities which lose their exemption status under 40 CFR 72.6 (b)(6).	The combustion turbine at SREC is classified as new utility units serving a generator with a nameplate capacity > 25 MW that can not claim the cogeneration exemption under 40CFR72.4(b)(4). Therefore, the combustion turbine is subject to the Acid Rain requirements. The acid rain regulation does not apply to the auxiliary boiler because it does not generate electricity for sale, direct or indirectly.

Regulation	Applies?	Applicability Criteria (Yes, No, P = Partially, U = Unknown)	Status/ Discussion
40 CFR 75 Continuous Monitoring	Yes	Establishes criteria for continuous monitoring required for sources subject to the Acid Rain Program. Establishes practices for monitoring and reporting of NOx, and SO_2 emissions, along with heat input and diluent.	The combustion turbine at SREC is subject to the Acid Rain Program and the reporting and quality assurance requirements of this part.
40 CFR 82, Subpart A and Subpart F (40 CFR 82.3 and 82.150-82.169) Protection of Stratospheric Ozone—Recordkeeping and Reporting; Recycling and Emissions Reduction (12/29/05)	No	Applies to facilities using appliances (air conditioner, chillers, refrigerators or freezers) or industrial process refrigeration equipment containing more than 50 pounds of a Class I or Class II refrigerant listed in Appendix F to 40 CFR 82, Subpart A.	SREC currently uses only R-134a and R-404a, these materials are not found on or made up of chemicals found on the list of Class I or Class II substances regulated under 40 CFR 82. SREC has no listed refrigerants and is not subject to the rule.
40 CFR 96 NOx Budget Trading Program for State Implementation Plans (NOx Budget States- AL, CT, DC, DE, IL, IN, KY, MA, MD, MI, NC, NJ, NY, OH, PA, RI, SC, TN, VA, WV (Phase 1); GA, MO (Phase 2)) (CAIR states – all states listed above plus AR, FL, IA, LA, MN, MS, TX, and WI) (5/12/05)	No	The NOx Budget Trading Program portion of the regulation applies to any fossil-fuel fired boiler, combustion turbine or combined cycle system that on or after 1/1/95 serves a generator with a nameplate capacity > 25MWe and sells any amount of electricity or any unit that does not meet the requirement above but has a maximum design heat input > 250 MMBtu/hr. The units must be located in one of the affected eastern states. All units listed above are exempt from this regulation if they have a federally enforceable permit which restricts their fuel usage to natural gas and fuel oil and restricts the number of operating hours in order not to exceed 25 tons potential NOx emissions during the ozone season in 2003 and later. The CAIR NOx Annual Trading Program portion of the regulation applies to any fossil-fuel fired boiler or combustion turbine that, since its startup, has served a generator with a nameplate capacity > 25MWe, sells any amount of electricity, and is located in one of the affected states. A cogeneration unit that is exempt from the Acid Rain regulations under 40 CFR 72.4(b)(4) is also exempt from this regulation.	SREC has a combustion turbine serving a generator with a nameplate capacity > 25 Mwe that do not meet the Acid Rain cogeneration exemption. SREC sells the electricity generated by the turbine. Florida is not one of the states included in the NOx Budget Trading Program. However Florida will be included in the CAIR NOx Annual Trading Program. Following the effective date of the CAIR rule, this regulation will apply to the facility.

Regulation	Applies?	Applicability Criteria (Yes, No, P = Partially, U = Unknown)	Status/ Discussion
40 CFR 97 Federal NOx Budget Trading Program (1/18/2000)	No	Applies to facilities with NOx Budget units, located in one of the eastern affected states, in which the state has not adopted 40 CFR 96 in its SIP.	Florida is not one of the states included in the NOx Budget Trading Program. Therefore, this regulation does not apply to the facility.
40 CFR 68 Chemical Accident Prevention (01/06/99)	No	Applies to a facility that has more than a threshold quantity of a regulated substance in a process. Regulated substances and respective threshold quantities are provided in Table 1 of 40 CFR 68.130.	SREC does not use ammonia for NOx control and does not have any substances on site above the threshold quantity.

REGULATORY APPLICABILITY SCREEN - STATE

Regulation	Applies?	Applicability Criteria (Yes, No, P = Partially, U = Unknown)	Status/ Discussion
Chapter 62-204 F.A.C. Air Pollution Control General Provisions	Yes	Establishes overall provisions for air permitting regulations and ambient air quality standards for criteria pollutants. Section 240 establishes Ambient Air Quality Standards. Section 260 establishes PSD increments. Section 340 Designates Attainment Areas. Section 360 designates PSD Areas, Section 800 adopts federal rules by reference.	The air quality standards and their attainment form the basis for permitting and for the evaluation of SREC's application. Adherence to the permit conditions should preclude a violation of the air quality standards.
Chapter 62-210 F.A.C. Stationary Sources – General Requirements	Yes	Establishes rules governing the issuance of air permits. Section 300 provides requirements for permitting. Section 350 governs public notice and comment requirements. Section 370 covers annual reporting requirements. Section 650 prohibits circumvention. Section 700 governs excess emissions. Section 900 provides forms and instructions	SREC is a source of air pollution subject to the requirement for air permitting.
Chapter 62-212 F.A.C. Stationary Sources – Preconstruction Review	Yes	Establishes rules governing Prevention of Significant Deterioration reviews. Section 300 establishes general preconstruction review requirements and annual report requirements. Section 400 establishes Florida construction review requirements for construction in clean air areas.	SREC is a major source of air pollution subject to PSD review. Modifications to the facility or operations may trigger provisions of this chapter.
Chapter 62-213 F.A.C. Operations Permits for Major Sources of Air Pollution	Yes	Establishes rules governing operating permits for major sources of air pollution (Title V Permits) including annual fees, forms and instructions, permit revisions and content, and permit shield.	SREC is a major source of air pollution subject to major source permitting.
Chapter 62-214 F.A.C. Federal Acid Rain Program	Yes	This chapter outlines the additional permitting requirements for Title V sources that are subject to the Federal Acid Rain Program. The rules under this chapter set forth requirements for the Acid Rain Part of an operation permit for a Title V source which is subject to the Federal Acid Rain Program.	SREC is a regulated source under the Acid Rain Program.
Chapter 62-256 F.A.C. Open Burning and Frost Protection Fires	Yes	Establishes certain prohibited activities such as open burning.	All state source are subject to these prohibitions
Chapter 62-296 Stationary Sources: Emissions Standards	Yes	Establishes general pollutant emission limiting standards applicable to all sources (objectionable odors, open burning, unconfined emissions of particulates). Provide applicable standards for particulate matter emissions and opacity for source categories including steam generators.	SREC is subject to standards for particulate matter and opacity. Standards have been incorporated into the site permit.
Chapter 62-297 Stationary Sources: Emissions Monitoring	Yes	Establishes requirements for source testing and continuous monitoring. Section 310 establishes general test requirements. Section 401 list compliance test methods. Section 520 incorporates EPA continuous monitor performance specifications. Section 620 establishes procedures for approval of alternate test methods.	SREC is subject to the requirements for annual testing and continousus monitoring.

SGS

October 17, 2005

CALPINE CORPORATION
HOG BAYOU ENERGY CENTER
1003 Papermill Road
Mobile, AL 36610

CERTIFICATE OF ANALYSIS

RE:	SUBMITTED SAMPLE
PRODUCT:	SAID TO BE NATURAL GAS
SUBMITTED BY:	CALPINE CORPORATION on 10/14/05
SAMPLE MARKS:	HOG BAYOU ENERGY CENTER; SREC DTD 08/08/05
OUR REF:	08-7851

COMPONENTS, MOLE %

TEST	RESULTS
METHANE	96.281
ETHANE	2.0047
PROPANE	0.38707
I-BUTANE	0.09259
N-BUTANE	0.08425
NEO-PENTANE	ND
I-PENTANE	0.02913
N-PENTANE	0.01939
N-HEXANES	ND
N-HEPTANES	ND
N-OCTANES	ND
N-NONANES	ND
N-DECANES	ND
HENDECANES	ND
DODECANES	ND
TRIDECANES	ND
TETRADECANES	ND
HYDROGEN	ND
NITROGEN	0.44733
OXYGEN	0.01902
ARGON	ND
CARBON DIOXIDE	0.63517
CARBON MONOXIDE	ND
WATER	ND
HYDROGEN SULFIDE, ppm	0.9
TOTAL SULFUR, ppm	0.9

CALPINE CORPORATION
HOG BAYOU ENERGY CENTER
1003 Papermill Road
Mobile, AL 36610

CERTIFICATE OF ANALYSIS 08-7851 (continued)

CALCULATED PROPERTIES	**RESULTS**
RELATIVE DENSITY	0.5803
HEATING VALUE, BTU/cf, GROSS, 14.73 psia, 60 deg. F	
SATURATED	1010
HIGHER HEATING VALUE (DRY)	1028
LOWER HEATING VALUE (NET)	926

ND = NOT DETECTED

Methods

Hydrocarbons – ASTM D-1945
Sulfur – ASTM D-5504
Relative Density – ASTM D-3588
Heating Values – ASTM D-3588

/S/: Stephanie A. Richards, Senior Chemist
SGS NORTH AMERICA INC.
MINERALS SERVICES DIVISION

SAR/rf

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Appendix G

Part 75 Monitoring Plan

FACILITY INFORMATION (RT 102)

ORIS Code/Facility ID: 55242 EPA AIRS ID: State ID:

Plant Name: SANTA ROSA ENERGY State: FL Latitude: 303358 Longitude: 870654

County Code: 113 County Name: SANTA ROSA Source Category/Type: ELECTRIC UTILITY

Primary SIC Code/Description: 4911 Electric Services

Add Quarter: 2006Q1

Update Quarter: 2006Q1

UNIT OPERATION INFORMATION (RT 504)

Unit ID	Unit Short Name	Boiler Type	Max Heat Input(mmBtu)	1st Comm Operation Date	Retirement Date	Stack Exit Height	Stack Base Elevation	Area At Stack Exit	Area At Flow Monitor	Non-Load-Based Unit
CT-1	UNIT CT-1	CT	1780.0	05/11/2002	/ /	200	92	283		

Boiler Type Codes: CT - Simple cycle combustion turbine

UNIT PROGRAM INFORMATION (RT 505)

Unit ID	Program	Unit Class	Reporting Frequency	Program Participation Date	State Regulation Code	State/Local Regulatory Agency Code
CT-1	ARP	P2	Q	05/11/2002		FL

Unit Class Codes: P2 - Phase II (ARP only)
Reporting Frequency Codes: Q - Quarterly

EIA Cross Reference Information (RT 506)

Unit ID	Part 75 Monitoring Location ID	EIA Boiler ID	EIA Flue ID	EIA Reporting Year	EIA 767 Reporting Indicator	EIA Facility ID
CT-1	CT-1			2000	N	

FUEL USAGE QUALIFICATION INFORMATION (RT 507)

				Capacity or Gas Usage									
Unit ID	Year of Qualification	Year1	Year1 Type	Year1%	Year2	Year2 Type	Year2%	Year3	Year3 Type	Year3%	Average%	Type of Qualification	Method of Qualifying
CT-1	2002	2002	P	100%	2003	P	100%	2004	P	100%	100%	GF	3PR
CT-1	2003	2002	A	100%	2003	P	100%	2004	P	100%	100%	GF	1HD
CT-1	2004	2002	A	100%	2003	A	100%	2004	P	100%	100%	GF	2HD
CT-1	2005	2002	A	100%	2003	A	100%	2004	A	100%	100%	GF	3HD

FUEL USAGE QUALIFICATION INFORMATION (RT 507)

Unit ID	Year of Qualification	Year1	Year1 Type	Year1%	Year2	Year2 Type	Year2%	Year3	Year3 Type	Year3%	Average%	Type of Qualification	Method of Qualifying
			Capacity or Gas Usage										
CT-1	2006	2004	A	100%	2005	A	100%	2006	A	100%	100%	GF	3HD

Gas Qualifying Codes: 1HD - One year of historical data; two projected, 2HD - Two years of historical data; one projected, 3HD - Three years of historical data, 3PR - Three years projected cap. factor or fuel use

Type of Qualification Codes: GF - Gas-Fired Qualification

UNIT/STACK/PIPE ID: CT-1

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Stat.	System ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Comp. ID	Stat.	Comp. Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	101	NOX	P	05/11/2002	/ /	101	A	NOXL	EXT	ROSEMOUNT ANALYTICAL	NGA CLD	U1005707
						102	A	O2D	EXT	ROSEMOUNT ANALYTICAL	MLT	30061481173
						103	A	DAHS		CONTEC	DATASOFT-WIN	VER. 2.0
A	102	GAS	P	05/11/2002	/ /	103	A	DAHS		CONTEC	DATASOFT-WIN	VER. 2.0
						104	A	GFFM	ORF	ROSEMOUNT INC.	3095 MV	0067321

Parameter Monitored Codes: GAS - Gas fuel flow, NOX - NOx emission rate
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, GFFM - Gas fuel flowmeter, NOXL - Low scale NOx analyzer, O2D - Dry O2 analyzer
SAM codes: EXT - Dry Extractive, ORF - Orifice
Status Codes: A - Add

Unit/Stack/Pipe ID: CT-1

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	101	NOX	19-1	NOx lb/mmbtu = 1.194 * 10**-7 * S#(101-101) * 8710 * (20.9/(20.9-s#(102-101)))
A	102	HI	F-20	MMBTU = S#(104-102) * GCVg / 10**6
A	103	CO2	G-4	WCO2 = 1040 * (F#(102) * (1/385) * 44) / 2000
A	104	SO2	D-5	MSO2 = F#(102) * 0.0006

Status Codes: A - Add
Parameter Codes: CO2 - CO2 mass emissions, HI - Heat input, NOX - NOx emission rate, SO2 - SO2 mass emissions

SPAN VALUES (RT 530)

Unit/ Stk ID	Para- meter	Sc.	Meth- od	MPC/ MEC/ MPF	Max. NOx Rate	Span Value	Full-Scale Range	Units of Meas.	Eff. Date and Hour	Inactive Date & Hour	Dual Spans Req.	Def. High Range Value
CT-1	NOX	H	TB	150.000	0.553	0	0	PPM	05/11/2002 00	/ /	O	300
	NOX	L	OL	9.800	0.036	20	20	PPM	05/11/2002 00	/ /	O	0
	O2	H	NA			25.0	25.0	%	05/11/2002 00	/ /		

Parameter Codes: NOX - NOx concentration, O2 - Oxygen
Scale Codes: H - High, L - Low
Method Codes: NA - Not Applicable, OL - Other limit, TB - Table of Constants
Units of Measure Codes: % - Percent, PPM - Parts per million
Dual Span Req. Codes: O - O Dual range req/using optional default

MAXIMUMS, MINIMUMS, DEFAULTS, AND CONSTANTS (RT 531)

Unit/Stack/ Pipe ID	Parameter	Value	Units of Measure	Purpose	Fuel Type	Source of Value	Controlled/ Uncontrolled Indicator	Begin Use of Value Date	Hr	Value No Longer Used Date	Hr
CT-1	O2X	19.000	%O2	DC	PNG	DCPD	A	05/11/2002	00	/ /	
	SO2G	0.0006	LBMMBTU	LM	PNG	LME	A	05/11/2002	00	/ /	

Parameter Codes: O2X - Maximum percent O2, SO2G - Generic SO2 default emission rate
Units of Measure Codes: %O2 - Percent O2, LBMMBTU - Pounds per million BTU
Purpose Codes: DC - Diluent Cap Value, LM - Low mass emission unit default
Source of Value Codes: DCPD - Diluent cap default: Part 75, LME - Low mass emission default
Fuel Type Codes: PNG - Pipeline natural gas

UNIT AND STACK LOAD RANGE AND OPERATING LOAD (RT 535)

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Three-load RATA Exemption Status
CT-1	MW	175	

RANGE OF OPERATION, NORMAL OPERATING LEVEL AND OPERATING LEVEL USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Operating Levels	Designated Normal Op. Level	Second Designated Normal Op. Level	Activation Date	Deactivation Date
CT-1	168	85	H,M	H	M	05/11/2002	/ /

FUEL FLOWMETER DATA (RT 540)

Unit/ Pipe ID	System ID	Parameter	Fuel Type	Maximum Fuel Flow Rate	Units of Measure	Source of Maximum	Initial Accuracy Test Method	Sub Status
CT-1	102	GAS	PNG	18293	HSCF	URV	AGA3	A

Parameter Codes: GAS - Gas fuel flow
Fuel Type Codes: PNG - Pipeline natural gas
Units of Measure Codes: HSCF - 100 standard cubic feet per hour
Source of Maximum Codes: URV - Upper Range Value
Submission Status Codes: A - Add

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
CT-1	CO2	GFF	PNG	P	SPTS	05/11/2002	/ /
	HI	GFF	PNG	P	SPTS	05/11/2002	/ /
	NOXR	CEM	NFS	P	SPTS	05/11/2002	/ /
	SO2	GFF	PNG	P	SPTS	05/11/2002	/ /

Parameter Codes: CO2 - Carbon Dioxide, HI - Heat Input, NOXR - NOx Emission Rate, SO2 - Sulfur Dioxide
Fuel Type Codes: NFS - Non-fuel specific, PNG - Pipeline natural gas
Methodology Codes: CEM - Continuous emission monitoring, GFF - Hourly gas flow
Missing Data Approach Codes: SPTS - Standard Part 75

CONTROL INFORMATION (RT 586)

Unit ID	Parameter	Type of Controls	Primary/ Secondary	Original Installation?	Controls Installation Date	Controls Optim-ization Date	Controls Retirement Date	Ozone Season Only?
CT-1	NOX	DLNB	P	O	04/01/2002	05/11/2002	/ /	

Parameter Codes: NOX - Nitrogen Oxides
Type of Controls Codes: DLNB - Dry Low NOx Burners (for turbine)

FUEL TYPE INFORMATION (RT 587)

Unit ID	Fuel Classification	Primary/ Secondary Fuel	Start Date	End Date	Ozone Season Flag	Method to Qualify for Monthly GCV	Method to Qualify for Daily % Sulfur
CT-1	PNG	P	05/11/2002	/ /			

Fuel Classification Codes: PNG - Pipeline natural gas