Santa Rosa Energy LLC

Santa Rosa Energy Center

Pace, Florida

Title V Air Operating Permit Application

March 2002

CALPINE

ISLAND CENTER
2701 N. ROCKY POINT DRIVE
SUITE 1200
TAMPA, FLORIDA 33607
813.637.7300
813.637.7399 (FAX)

RECEIVED
APR 01 2002
BUREAU OF AIR REGULATION

March 29, 2002

Mr. Scott Sheplak
Bureau of Air Regulation
111 South Magnolia Drive
Suite 4
Tallahassee, Florida 32301

Re: Santa Rosa Energy, LLC
Santa Rosa Energy Center
Application for Air Operating (Title V) Permit
Project No.: 1130168-004-AV

Dear Mr. Sheplak:

Enclosed please find two copies of the subject permit application. The Santa Rosa Energy Center is currently under construction under the construction permit number PSD-FL-253. Initial operation of the facility is expected during April of 2002.

If you have any questions regarding the enclosed submittal or require additional information, please do not hesitate to contact me by telephone at (813) 637-7305 or via email at bborsch@calpine.com

Sincerely,

Santa Rosa Energy, LLC

Benjamin M. H. Borsch

Benjamin M. H. Borsch, P.E.
Environmental Manager

Cc: Ms. S. Veazy, NW District Air Program (w/ enclosure)
Mr. A. Linero, Bureau of Air Regulation (w/o enclosure)
Mr. Ted Baldwin, Calpine

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BUREAU OF AIR REGULATION

Table of Contents

1. Application Summary

Santa Rosa Energy Center, LLC is constructing a combined cycle cogeneration facility near Pace, Florida to supply electricity to the electrical grid. The facility is located 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 an application for an operation permit for the Energy Center. The Energy Center is classified as a major stationary source as defined in the Florida Administrative Code, Chapter 62-213, F.A.C. 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), sulfur dioxide (SO_2), and carbon monoxide (CO). The Energy Center began construction in January of 2001 and expects to be prepared to perform emissions testing in compliance with the air construction permit (PSD-FL-253) by June 30, 2002. Application for an operating permit is required at least 90 days prior to the expiration date of the PSD permit, in this case June 30, 2002. With this document, Calpine has provided the data, demonstrations, certifications, and application forms required.

1.1. Site Description

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

1.2. Description of Expected Operations

The primary components of the cogeneration facility are the combustion turbine, steam turbine, heat recovery steam 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 will not be included in this permit application. The combustion turbine will operate exclusively on natural gas. The combustion turbine has an electric generation capacity of approximately 178 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 Administrative Code incorporate the concept of an application shield for sources required to obtain a major source operating permit.

SREC request that the permit application shield be established for this 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 Administrative 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, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

Calpine 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

Calpine operates the Energy Center cogeneration facility under Standard Industrial Classification code 4931, Independent Electricity and Steam Generation. The primary components of the cogeneration facility are a combustion turbine, steam turbine, and a HRSG equipped. 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 NO_X emissions from the combustion turbine is achieved via the use of Dry Low NO_X combustors for natural gas firing which will reduce NO_x emitted to less than 9 ppmvd at 15% O_2. The duct burners to be installed in the HRSG were included in the PSD permit. These have not been installed and are not reflected in this permit application.

The HRSG is a triple pressure unit providing its high pressure and intermediate pressure steam to the steam turbine. Low pressure steam is used within the Energy Center primarily for the HSRG deaerator with a small amount going to the low pressure section of the steam turbine or to Sterling Fibers for process use. During operation for the Sterling Fibers facility, the Energy Center will route most of the intermediate pressure steam from the HRSG to the Sterling Fibers process steam header for process use.

The combustion turbine will fire natural gas with the exhaust air stream directed to the HRSG for steam generation.

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.

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

3. Emission Inventory

Emissions of both criteria pollutants (CO, NO_X, PM, SO_2) and non-criteria pollutants (VOC and HAP) are estimated. The emissions for criteria pollutants are based on the limits established in the PSD permit PSD-FL-253, issued December 4, 1998 and extended on May 25, 2000.

3.1. Air Emissions Summary

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

Table 3-1 provides a listing of the potential emissions for PM, SO_2, NO_X, CO, VOC, and hazardous air pollutants (HAP) from the Energy Center. The emission levels presented for criteria pollutants reflect 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 Resources Board (CARB). Documentation for all emissions represented in this application is provided in Appendix C.

TABLE 3-1. POTENTIAL COMBUSTION TURBINE EMISSIONS OF PM, SO_2, NO_X, CO, VOC, AND HAP

Pollutant	Potential Emissions (tpy)	Major Source (Yes/No)
PM	42	No
SO_2	22	No
NO_X	281	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 and contributions form these emissions . Projected emissions values from these units are shown in Appendix B.

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, record keeping, 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 for all Federal and State air quality regulations. Specific listings of applicable regulations are found on Form 62-210.900(1) found in Section 6.

4.1. Federal Regulatory Applicability

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

4.1.1. New Source Performance Standards (NSPS)

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the 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. Following is a summary of the NSPS that apply to the Santa Rosa Energy Center.

4.1.1.1. NSPS Subpart A - General Provisions[1]

Any source subject to a source-specific NSPS (in the case of the Energy Center, NSPS Subparts Da and 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 startup notification;
Performance tests;
Performance test date initial notification;
General monitoring requirements;
General record keeping requirements; and
Semiannual monitoring system and/or excess emission reports.

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[1] 40 CFR §60.1.

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

4.1.1.2. NSPS Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978[2]

NSPS Subpart Da provides standards of performance for electric utility steam generating units, capable of combusting more than 250 MMBtu/hr heat input from fossil fuel (alone or in combination with another fuel), for which construction or modification commenced after September 18, 1978. The HRSG was initially permitted for duct burners with a heat input of 585 MMBtu/hr when combusting natural gas, which would have made the unit subject to Subpart Da.

Due to the elimination of the duct burners, Subpart Da is not applicable to the Santa Rosa Energy Center.

4.1.1.3. SPS Subpart GG - Standards of Performance for Stationary Gas Turbines[3]

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. NO_X emission standards for natural gas combustion and fuel oil combustion are 114 ppmvd and 97.6 ppmvd, respectively.[4]

The requirements for SO_2 under this subpart are an emission limit of 150 ppmvd (at 15% oxygen) or a fuel sulfur limit of 0.8% by weight.

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[2] 40 CFR §60.40a.

[3] 40 CFR §60.330

[4] 40 CFR §60.332(b)

4.1.2. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

The NESHAP, like the NSPS, establish emissions standards and work practice requirements for specific source categories and are codified at 40 CFR §63.[5] 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.[6] NESHAP 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 from 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 in 40 CFR Part 61 and 40 CFR Part 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 *et seq.*) of the Clean Air Act Amendments of 1990 established the Acid Rain Program (ARP) to substantially reduce SO_2 and NO_X emissions from electric utility plants. Affected units are specifically listed in Tables 1 or 2 of 40 CFR § 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."[7] As such the combustion turbine along with the HRSG, referred to as a combined cycle combustion turbine (CCCT), at the Energy Center are subject to the ARP regulations since it is a fossil fuel-fired combustion devices (i.e., units) that generates electricity to be sold (i.e., utility units). Accordingly, all subparts of the Acid Rain Program are potentially applicable to the Energy Center. The potentially applicable subparts are identified as follows:

- 40 CFR Part 72, Permits Regulations;

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[5] Additional NESHAP, derived from the 1970 Clean Air Act Amendments, are promulgated at 40 CFR §61; however, these standards only apply to certain pollutants emitted from certain regulated processes, none of which apply to the Energy Center.

[6] 40 CFR § 63.60 identifies pollutants removed from the defined HAP list.

[7] 40 CFR § 72.2.

- 40 CFR Part 73, Allowance System;
- 40 CFR Part 75, Continuous Emission Monitoring;
- 40 CFR Part 77, Excess Emissions; and
- 40 CFR Part 78, Appeal Procedures for Acid Rain Program.

4.1.3.1. ARP PERMITS REGULATION - 40 CFR 72

The pertinent subparts of this section are Subparts A, B, C, and I. Subpart A of 40 CFR 72 outlines the general requirements for sources and units affected by the ARP such as permit, monitoring, emission, record keeping and reporting, and liability. Subpart B lists the requirements and responsibilities associated with the title of designated representative. Subpart C contains the requirements for ARP permit applications. Subpart I provides requirements for compliance certification, specifically the annual compliance certification report.[8]

4.1.3.2. SULFUR DIOXIDE ALLOWANCE SYSTEM - 40 CFR 73

Part 73 establishes requirements for the allocation of SO_2 emissions allowances and the maintenance of the account using the Allowance Tracking System maintained by U.S. EPA for each ton of SO_2 emissions per year.

4.1.3.3. CONTINUOUS EMISSION MONITORING - 40 CFR 75

Part 75 provides the unit specific requirements for monitoring, record keeping, and reporting of SO_2, NO_X, and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data.[9] The combustion turbine and HRSG with duct burner are subject to the continuous monitoring requirements of 40 CFR 75.

40 CFR 75 Subpart B sets forth monitoring provisions for opacity, SO_2, NO_X, and CO_2 emissions for all affected units (in this case, the CCCT).[10] Specific provisions for monitoring opacity for gas-fired units[11] under 40 CFR § 75.14(c) state that a unit qualifying as gas-fired, based on information submitted by the designated representative in the monitoring plan, is exempt from the opacity monitoring requirements of Part 75. The CCCT at the Energy Center qualifies as a gas-fired unit; therefore it is exempt from the opacity monitoring requirements.

4.1.3.4. EXCESS EMISSIONS - 40 CFR 77

Excess emission occurrences require payment of penalties. The penalty per ton of excess SO_2 or NO_X is determined using the base value of $2,000 and an

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[8] 40 CFR § 72.90.

[9] 40 CFR § 75.1(a)

[10] 40 CFR § 75.10(a)

[11] 40 CFR § 72.2

annual adjustment factor based on the Consumer Price Index (CPI) for 1990 and the current year. Payment is required within 30 days of notice that recordation has occurred for the year in which the excess emissions occurred.[12]

In addition to the penalty payment, the designated representative must submit an offset plan within 60 days after the end of the calendar year in which the excess SO_2 emissions occurred.[13] The plan must include the following:

- Identification number for the unit.
- Whether the unit had excess emissions in the previous year.
- Explanation of how and why the excess emissions occurred.
- Any measures taken to prevent excess emissions in the future.
- Number of allowances deducted and their serial numbers, optional.
- Statement indicating whether the excess emissions will be deducted from the unit's compliance subaccount or whether they will be deducted on a specified future date if it can be demonstrated that a current deduction will interfere with electric reliability.

The U.S. EPA will determine whether the offset plan is complete within 30 days of submission. Even if complete, additional information may be requested. Using the submitted plan, U.S. EPA will prepare a draft plan that is subject to a 30-day public comment period. The designated representative will receive a copy of all public comments. The comments will be considered and the final plan approved or revised.

4.1.4. STRATOSPHERIC OZONE PROTECTION REGULATIONS

40 CFR 82 Subpart F, Stratospheric Ozone Protection, applies to the maintenance of refrigeration equipment at facilities that contain ozone-depleting substances. Calpine relies upon subcontracted maintenance assistance for any maintenance operation performed on the refrigeration equipment that is subject to this regulation. Calpine verifies certification of the subcontractor personnel and equipment upon procurement of services.

4.2. FDEP Regulations

FDEP regulations fall under two main categories, those regulations that are generally applicable (e.g., permitting requirements), and those that have specific applicability (e.g., PM standards for manufacturing equipment). The generally applicable requirements are straightforward (e.g., filing of emission statements) and, as such, are not discussed in further detail. The specific requirements associated with several regulations are detailed in the applicable requirements portion of Form 62-210.900(1).

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[12] 40 CFR §77. 6

[13] 40 CFR §77. 4

4.3. *Current State Air Permit Provisions*

The remaining requirements with which the Energy Center must comply with are the provisions contained in the state air permits previously issued to the facility. Permit provisions common to all emission units (with the exception of emission limits) are:

- Compliance with future rules and regulations upon promulgation;
- Application for new operating permit– apply within 30 days of facility transfer or sale;
- Revision of permit for new sources, replacements, alterations, design changes, or control devices;
- Provision of sampling ports, ladders, platforms, and other safety equipment to facilitate testing (except distillate fuel oil storage tank);
- Operation of air pollution control devices and capture systems at all times with the goal of minimizing air contaminant emissions;
- Notification to the Department within 24 hours if a breakdown of equipment causes increased emission of air contaminants;
- Submission of reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required;
- Additions and revisions to the conditions of this Permit will be made, if necessary;
- Nothing in this Permit or conditions thereto shall negate any authority granted to the Department pursuant to Florida Statues;
- Precautions to prevent fugitive dust shall be taken; and
- Measures to abate odorous emissions shall be taken if necessary.

5. Compliance Certification and Plan

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

- The Energy Center will monitor and ensure compliance with the majority of the applicable requirements via the continuous emissions monitor (CEM) for the combustion turbine stack.
- Required monitoring reports will be submitted electronically each quarter, using data supplementing procedures per 40 CFR Subpart 75. Additionally, excess emissions reports are submitted to FDEP quarterly as required in the facility PSD Condition 29.
- Calpine will submit quarterly Acid Rain monitoring reports for SO_2 and NO_X.
- As required by the PSD 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, record keeping, 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 emissions limits and compliance requirements meet the intent of the applicable NSPS requirements.
- Permit Conditions 24 and 45 requires that compliance with the SO_2 emission limit shall be demonstrated via fuel sulfur content and through a custom fuel monitoring program.
- The Combustion Turbine NOx Monitoring Plan, submitted to FDEP on March 6, 2002 is attached as Appendix D. This plan as approved by the department will serve as the compliance plan for all initial start up and testing. Ongoing compliance will be in accordance with the requirements of PSD permit PSD-FL-253, 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 as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete."

Robert K. Alff

Robert K. Alff, Senior Vice President

3/29/02

Date

6. Permit Application Forms

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

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

Application Contact

1. Name and Title of Application Contact: *Benjamin Borsch, P.E., Environmental Manager*
2. Application Contact Mailing Address: Organization/Firm: *Santa Rosa Energy LLC* Street Address: *2701 N. Rocky Point Drive, Suite 1200* City: *Tampa* State: *FL* Zip Code: *33607*
3. Application Contact Telephone Numbers: Telephone: (813) 637-7305 Fax: (813) 637-7395

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:____________________

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

Current construction permit number:____________________

Operation permit number to be revised:____________________

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

Operation permit number to be revised/corrected:____________________

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

Operation permit number to be revised:____________________

Reason for revision:____________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: *Robert K. Alff, Senior Vice President*	
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: *Santa Rosa Energy LLC* Street Address: *2701 N. Rocky Point Drive, Suite 1200* City: *Tampa* State: *FL* Zip Code: 33607	
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: *(813) 637-7300* Fax: (*813*)637-7399	
4. Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [✓], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Robert K. Alff 3/29/02 Signature Date	

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: *Benjamin M. H. Borsch* Registration Number: *0043875*	
2. Professional Engineer Mailing Address: Organization/Firm: *Calpine Eastern Corporation* Street Address: *2701 N. Rocky Point Drive, Suite 1200* City: *Tampa* State: *FL* Zip Code: *33607*	
3. Professional Engineer Telephone Numbers: Telephone: (813) 637-7305 Fax: (813) 637-7395	

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

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

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

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

Benjamin M.H. Borsch
Signature

3/29/02
Date

(seal)

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

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
EU-001	*168 MWe (nominal) Natural Gas Fired Combustion Turbine*		
EU-003	*Wet Cooling Tower*		

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations:

Initial operating permit for 167 (nominal) mW combustion turbine with HRSG and associated steam turbine. Construction permit included 565 mmBtu/hr duct firing of HRSG. Duct firing of HRSG is not included in this operating permit. See Section 2.2 of the report text.

2. Projected or Actual Date of Commencement of Construction:

January 2001

3. Projected Date of Completion of Construction:

See comment below.

Application Comment

In accordance with the PSD permit (PSD-FL-253), compliance and CEMS certification testing will be completed prior to June 30, 2002. Final mechanical completion of other portions of the plant, not necessary to the emissions units (e.g. the steam turbine) will be accomplished at a later date. Estimated commercial operation of the facility is now set for 2nd quarter 2003.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: *16*	East (km): *488,974*		North (km): *3,381.526*
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): *30° 33' 58.3"*		Longitude (DD/MM/SS): *87° 06' 54.1"*	
3. Governmental Facility Code: *0*	4. Facility Status Code: *C*	5. Facility Major Group SIC Code: *49*	6. Facility SIC(s): *4931*
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: *Dane Hill, Facility Environmental Coordinator*
2. Facility Contact Mailing Address: Organization/Firm: *Santa Rosa Energy, LLC* Street Address: *1003 Papermill Road* City: *Mobile* State: *AL* Zip Code: *36610*
3. Facility Contact Telephone Numbers: Telephone: *(251) 330-1031* Fax: *(251) 330-1093*

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source? [ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?
5. [ ] Synthetic Minor Source of HAPs?
6. [X] One or More Emissions Units Subject to NSPS?
7. [ ] One or More Emission Units Subject to NESHAP?
8. [X] Title V Source by EPA Designation?
9. Facility Regulatory Classifications Comment (limit to 200 characters): *Please see Section 3.1.2 of the report text for additional information.*

List of Applicable Regulations

Chapter 62-4	*Permits – General Procedures for Permitting*
Chapter 62-4, Rule 62-4.050 (4)(a)(1)	*Processing Fee Air Pollution Permits*
Chapter 62-103	*Administrative Procedure – Public Notice of Application, Proposed Agency Action, and Petition for Administrative Hearing*
Chapter 62-204, Rule 62-204.220	*Ambient Air Quality Protection*
Chapter 62-204, Rule 62-204.240 (1)(d)	*Ambient Air Quality Standards*

Chapter 62-204, Rule 62-204.260	*Prevention of Significant Deterioration Increments*
Chapter 62-204, Rule62- 204.360	*Designation of Prevention of Significant Deterioration Areas*
Chapter 62-204, Rule 62-204.800	*Federal Regulations Adopted be Reference*
Chapter 62-210, Rule 62-210.300 (1)	*Air Permits Required (Air Construction)*
Chapter 62-210, Rule 62-210.300 (2)	*Major Source Operating Permits*
Chapter 62-210, Rule 62-210.300 (3)	*Exemptions*
Chapter 62-210, Rule 62-210.300 (5)	*Notification of Startup (Applies to facilities with operating permits where there are extended shutdown periods greater that 1 year.)*
Chapter 62-210, Rule 62-210.300 (6)	*Emissions Unit Reclassification (Applies to facilities with expired or revoked operating permits.)*
Chapter 62-210, Rule 62-210.350	*Public Notice and Comments (References Chapter 62.103) Additional notices are required for Title V facilities.*
Chapter 62-210, Rule 62-210.370	*Reports (Annual Reporting Requirements)*
Chapter 62-210, Rule 62-210.550	*Stack Height Policy*
Chapter 62-210, Rule 62-210.650	*Circumvention*
Chapter 62-210, Rule 62-210.700	*Excess Emissions*
Chapter 62-210, Rule 62-210.900	*Forms and Instructions*
Chapter 62-212, Rule 62-212.300	*General Preconstruction Review Requirements and Annual Reports (Forms and Instructions)*
Chapter 62-212, Rule 62-212.400	*Prevention of Significant Deterioration (PSD) – Florida construction review requirements for construction in clean air areas.*

Chapter 62-213, Rule 62-213	*Operating Permits for Major Sources of Air Pollution (Annual Fees, Forms and Instructions, Permit Revisions and Content, and Permit Shield)*
Chapter 62-214, Rule 62-214	*Requirements for Sources Subject to the Federal Acid Rain Program*
Chapter 62-256, Rule 62-256	*Prohibitions (Opening Burning)*
Chapter 62-296, Rule 62-296.320	*General Pollutant Emission Limiting Standards (Objectionable Odors, Open Burning, Unconfined Emissions of Particulate Matter)*
Chapter 62-297, Rule 62-297.310	*General Test Requirements*
Chapter 62-297, Rule 62-297.401	*Compliance Test Methods*
Chapter 62-297, Rule 62-297.520	*EPA Continuous Monitor Performance Specifications*
Chapter 62-297, Rule 62-297.620	*Exceptions and Approval of Alternate Procedures and Requirements. (Testing)*
40 CFR Part 52, Section 52.21	*Prevention of significant deterioration of air quality. Those parts of the CFR in addition to or more stringent than the requirements in FDEP rules (62-212.400)*
40 CFR Part 72 and 75	*Acid Rain Program (NO_x) and Continuous Emissions Monitoring*
40 CFR Part 60, Subpart A	*General Provisions, New Source Performance Standards*
40 CFR Part 60, Subpart GG (60.330 through 60.335)	*Standards of Performance for Stationery Gas Turbines*
See Section 4 of the report text for additional information.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

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

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: _*Appendix A*_ [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: _*Appendix A*_ [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: _*Appendix A*_ [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: *Section 5* [ ] Not Applicable [ ] Waiver Requested *Please see Section 5 of the report text*
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID: [X] Not Applicable
7. Supplemental Requirements Comment:

C.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [X] Attached, Document ID:__Appendix B______ [ ] Not Applicable	
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [X] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable	
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [X] Not Applicable	
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable	
12. Identification of Additional Applicable Requirements: [X] Attached, Document ID:________ [ ] Not Applicable	
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [X] Not Applicable	
14. Compliance Report and Plan: [ ] Attached, Document ID:___ *Section 5*_____ [ ] Not Applicable	
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:__*Section 5*___ [ ] Not Applicable	

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
168 Mwe (nominal) Natural Gas Fired Combustion Turbine with Heat Recovery Steam Generator

4. Emissions Unit Identification Number: ID: *EU-0001*
[ ] No ID
[ ] ID Unknown

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

9. Emissions Unit Comment: (Limit to 500 Characters)
The combustion turbine will be a General Electric Frame 7FA. The unit has a nominal rating of 168 MWe at 100% load, 1,780 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

A.

1. Control Equipment/Method Description (Limit to 200 characters per device or method): *Dry Low NO_x Technology is an integral part of the combustion turbine design and reduces the potential for thermal NO_x formation through combustion control and burner design.*
2. Control Device or Method Code(s): *025*

B.

1. Control Equipment/Method Description (Limit to 200 characters per device or method): *Clean fuel (natural gas) will be combusted in the combustion turbine. This code (030) is the closest match for low sulfur fuel, also.*
2. Control Device or Method Code(s): *030*

Emissions Unit Details

1. Initial Startup Date: *April 2002*
2. Long-term Reserve Shutdown Date: *Not Applicable*
3. Package Unit: *Combustion Turbine* Manufacturer: *General Electric* Model Number: *GE MS7001FA*
4. Generator Nameplate Rating: *Appr. 159 Simple Cycle and 241 Combined Cycle* MW *Unit will not be operated in Simple Cycle mode*
5. Incinerator Information: *Not Applicable* Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			mmBtu/hr
1,908 MMBtu/hr @ PWR AUG mode and 40 ° Ambient Temperature Conditions			
2. Maximum Incineration Rate:	lb/hr		tons/day
Not Applicable			
3. Maximum Process or Throughput Rate:			
Not Applicable			
4. Maximum Production Rate:			
189 MWe @ 40 °F ambient temperature (simple cycle)			
5. Requested Maximum Operating Schedule:			
24	hours/day	*7*	days/week
52	weeks/year	*8,760*	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			
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 proposed site. The combustion turbine will operate normally above 50% load.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

Chapter 62-204, Rule 62-204 (1)(d)	*Ambient Air Quality Standards*
Chapter 62-210, Rule 62-210.300 (1)	*Air Permits*
Chapter 62-212, Rule 62-212.400	*Prevention of Significant Deterioration (PSD) – Florida construction review requirements for construction in clean air areas.*
40 CFR Part 52, Section 52.21	*Prevention of significant deterioration of aire quality. Those parts in addition to requirements in FDEP rules (62-212.400*
40 CFR Part 72 and 75	*Acid Rain Program (No_x) and Continuous Emission Monitoring*
40 CFR Part 60, Subpart A	*General Provisions, New Source Performance Standards*
40 CFR Part 60, Subpart GG (60.330 through 60.335)	*Standards of Performance for Stationary Gas Turbines*
40 CFR 60§60.332(a)(1)	*Natural Gas Firing: NO_x emissions shall not exceed 0.0075* (14.4/ Rated Capacity in kJ/Watt-Hr)+ F, where rated capacity for the worst-case operating mode is 13.48 kJ/Watt – Hr for 1,101.9 MMBtu/hr heat input and 77.6 MWe. F is 0. This correlates to an emission limited of 0.0080% NO_x @15% O_2, dry basis or 80 ppmvd @ 50% O_2, for Santa Rosa Energy Center at 50% load and 92°F based on vendor data for near ISO conditions. This case represents the most stringent limit for all operating modes.*
40 CFR 60§60.332(f)	*Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine. Santa Rosa Energy Center does not use water injection to control emissions. Steam is injected during the power augmentation mode only, and is not used to control emissions.*
40 CFR 60§60.333(a)	*SO_2 emissions shall never exceed 150 ppmv @ 15% O_2 dry basis.*

40 CFR 60§60.333(b)	*Fuel shall not be burned which is in excess of 0.8% by weight sulfur.*
40 CFR 60§60.334(a)	*The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NO_x emissions shall install and operate a continuous monitoring sustem to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within +5.0 percent and shall be approved by the Administrator. Santa Rosa Energy Center does not use water injection to control emissions. Steam is injected during the power augmentation mode only, and is not used to control emissions.*
40 CFR 60§60.334(b)	*Sulfur and nitrogen content of fuel being fired. Santa Rosa Energy LLC is proposing that NO_x CEMS be used in lieu of daily monitoring of the nitrogen content in the natural gas fired in the combustion turbine and because pipeline quality natural gas will be fired.* *Santa Rosa Energy LLC is also proposing that in lieu of daily monitoring of the sulfur content of natural gas, that upon startup of the combustion turbine operation, sulfur content of the natural gas will be monitored bimonthly for the first six months of operation. If analysis indicates little variability and compliance with 40 CFR 60.333, then monitoring will be conducted once per quarter for six months. If the analysis continues to indicate little variability and compliance with 40 CFR 60.333, then monitoring will be conducted twice annually during the first and third quarters of each year. Should an analysis indicate sulfur above the allowable level in 40 CFR 60.333, FDEP will be conducted and the custom monitoring schedule will be re-examined.*
40 CFR 60§60.334(c)	*Monitoring of Operations – For the purpose of reports required under §60.7(c).*

40 CFR 60§60.335	*Performance Testing Requirements.*
Appendix C contains a copy of the PSD permit (PSD-FL-253)	*Specific Performance, record keeping, and reporting requirements.*

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? *STK-0001*	2. Emission Point Type Code: *1*

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): *The natural gas-fired combustion turbine exhaust gases will pass through the heat recovery steam generator (HRSG) and exit through the stack.*
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: *EU-0001*

5. Discharge Type Code: *V*	6. Stack Height: *200* feet	7. Exit Diameter: *19* feet
8. Exit Temperature: Appr. 196 - 216 °F	9. Actual Volumetric Flow Rate: *See Comments* *1,073,204* acfm	10. Water Vapor: *Approximately 10* %

11. Maximum Dry Standard Flow Rate: *See Comments* *786,315* dscfm	12. Nonstack Emission Point Height: *Not Applicable* feet

13. Emission Point UTM Coordinates: Zone: *16* East (km): *488.974* North (km): *3,381.526*
14. Emission Point Comment (limit to 200 characters): *The stack flow rate is calculated from the combustion turbine exhaust data provided from the manufacturer for operation in the "Power Augmentation Mode".*

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

Segment Description and Rate: Segment ___1__ of ___1__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): *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 x 10^6 scf @ 1,000Btu/scf*	5. Maximum Annual Rate: 16,714 x *10^6 scf @ 1,000 Btu/scf*	6. Estimated Annual Activity Factor: *Not Applicable*
7. Maximum % Sulfur: *Negligible*	8. Maximum % Ash: *Negligible*	9. Million Btu per SCC Unit: *1,000 MMBtu/10^6 scf*
10. Segment Comment (limit to 200 characters): *Several Sources Classification Codes (SCC) were close matches to the proposed unit, however, the SCC used is the same as that used for US EPA AP-42 5th. Ed. Section 3.1. (Note: vendor emissions information was used in calculations for all emissions estimates rather that values present in Section 3.1 of AP-42).*		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: *CO*	2. Total Percent Efficiency of Control: *Not Applicable*	
3. Potential Emissions: *29* lb/hour *127* tons/year *Emissions based on ISO conditions as reflected in PSD permit*		4. Synthetically Limited? *No*
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: *0.0163 lb/MMBtu* Reference: *Manufacturer Data*		7. Emissions Method Code: *5*
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for CO: 9 ppmv and 29 lb/hr ISO conditions and 1780 MMBtu/hr (HHV)* *Annual Emissions Calculation* *29 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 127 ton/yr*		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *OTHER BACT*	2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *Not to exceed 9 ppm_{vd} corrected to 15% O_2 and 29 lb/hr. These values are consistent with the PSD permit.*	4. Equivalent Allowable Emissions: *29* lb/hour *127* tons/year
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): *Allowable emissions shall be consistent with limitations set forth in the PSD permit (PSD-FL-253).*	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: *NOX*	2. Total Percent Efficiency of Control: *Not Applicable*
3. Potential Emissions: *64.1* lb/hour *280.75* tons/year *Emissions based on ISO conditions as reflected in PSD permit*	4. Synthetically Limited? *No*
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: *0.036 lb/MMBtu (HHV)* Reference: *Manufacturer Data*	7. Emissions Method Code: *5*
8. Calculation of Emissions (limit to 600 characters): *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 * 8,760 hr/yr / 2,000 lb/ton = 280.75 ton/yr*	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *OTHER BACT*	2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *9 ppm_{vd} @ 15% O_2 based on 24 hour block average. Values are consistent with PSD permit.*	4. Equivalent Allowable Emissions: *64.1* lb/hour *280.75* tons/year
5. Method of Compliance (limit to 60 characters): *NOX CEMS (CEMS are proposed to also be used in lieu of nitrogen fuel sampling.)*	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters). *This proposed emission restriction is more stringent than that required be 40 CFR Part 60, Subpart GG, Section 60.332(a)(1) which was calculated to be approximately 80 ppmvd @ 15% O_2 for the worst cast load and ambient conditions.* *Allowable emissions shall be consistent with limitations set forth in the PSD permit (PSD-FL-253).*	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: *PM*	2. Total Percent Efficiency of Control: *Not Applicable*
3. Potential Emissions: *9.5* lb/hour *41.6* tons/year	4. Synthetically Limited? *No*
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: *0.0051 lb/MMBtu* Reference: *Manufacture Data*	7. Emissions Method Code: *5*
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for PM: 9.5 lb/hr or less at all loads (front half only).* *Annual Emissions Calculation* *9.5 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 41.6 ton/yr*	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): *General Electric emissions data provides a maximum emission value for all modes of operation.*	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *OTHER BACT*	2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *VE test, not to exceed 10% opacity. Tested via Method 9 in accordance with the requirements of the PSD permit.*	4. Equivalent Allowable Emissions: *9.5* lb/hour *41.6* tons/year
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): *Allowable emissions shall be consistent with limitations set forth in the PSD permit (PSD-FL-253).*	

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

Potential/Fugitive Emissions

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? *No*
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: *0.0051 lb/MMBtu* Reference: *Manufacture Data*		7. Emissions Method Code: *5*
8. Calculation of Emissions (limit to 600 characters): *Manufacture Data for PM: 9.5 lb/hr or less at all loads.* *<u>Annual Emissions Calculation</u>* *9.5 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 41.6 ton/yr*		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): *General Electric emissions data provides a maximum emission value for all modes of operation.*		

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *OTHER BACT*	2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *VE test, not to exceed 10% opacity. Tested via Method 9 in accordance with the requirements of the PSD permit.*	4. Equivalent Allowable Emissions: *9.5* lb/hour *41.6* tons/year
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): *Allowable emissions shall be consistent with limitations set forth in the PSD permit (PSD-FL-253).*	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: *SO2*	2. Total-Percent Efficiency of Control: *Not Applicable*	
3. Potential Emissions: *10.2* lb/hour *Emissions based on ISO conditions*	*44.5* tons/year	4. Synthetically Limited? *No*

5. Range of Estimated Fugitive Emissions: *Not Applicable*
[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor: *0.0006 lb/MMBtu* Reference: *Engineering Calculations*	7. Emissions Method Code: *5*

8. Calculation of Emissions (limit to 600 characters):
10.2 lb/hr at ISO conditions based on 2.0 grains sulfur / 100 scf nat. gas. OK

Emission Factor Calculation for Long-term Emissions
*0.02 gr/scf * lb/7,000 gr * 1,000 scf/MMBtu * 64.06 mol SO_2 / 32.06 mol S * 1,780 MMBtu/hr heat input PWR AUG @ 40°F (worst-case load) = 10.2 lb/hr*

Annual Emissions Calculation
*10.2 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 44.5 ton/yr*

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

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *ESCPSD*	2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *Natural Gas Usage*	4. Equivalent Allowable Emissions: *10.2* lb/hour *44.5* tons/year

5. Method of Compliance (limit to 60 characters):
Compliance will be assured by only using natural gas to fire the combustion turbine. Fuel analyses required by NSPS rules will be performed according to approved fuel monitoring schedule.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
The emission restriction per 40 CFR Part 60, Subpart GG, Section 60.333(a) is 150 ppmvd @ 15% O_2. Only natural gas will be fired in the combustion turbine and the SO_2 emissions will be far less than this 150 ppmv standard or the fuel sulfur content limit of 0.8%wt. and the 40 significant tpy increase PSD threshold.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: *VOC*	2. Total Percent Efficiency of Control: *Not Applicable*
3. Potential Emissions: *2.9* lb/hour *12.7* tons/year *Emissions based on ISO conditions as reflected in PSD permit*	4. Synthetically Limited? *No*
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: *0.0017 lb/MMBtu or 1.7 lb/10^6 scf. Nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*	7. Emissions Method Code: *5*
8. Calculation of Emissions (limit to 600 characters): *Manufacture Data for VOC: 1.4 ppm and 2.9 lb/hr* *Annual Emissions Calculation* *2.9 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 12.7 ton/yr*	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *OTHER BACT*	2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *Not to exceed 1.4 ppm and 2.9 lb/hr, demonstrated by the initial stack test as required in the PSD permit.*	4. Equivalent Allowable Emissions: *2.9* lb/hour *12.7* tons/year
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with record keeping of fuel usage.*	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): *Good combustion practices will be used to maintain VOC emissions at or below the equipment design emissions value specified in item 3 under Requested Allowable Emissions. All other conditions required by the PSD permit will be maintained.*	

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

Potential/Fugitive Emissions

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? *No*
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: *AP-42 and CARB factors. See Appendix F*	7. Emissions Method Code: *5*
8. Calculation of Emissions (limit to 600 characters): *See Appendix F*	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ______ of ______

1. Basis for Allowable Emissions Code: *ESCMACT*	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with record keeping of fuel usage.*	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___2___

1. Visible Emissions Subtype: *VE10*	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: *10 % (6 min. avg.)* Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: *one period of 6* min/hour	
4. Method of Compliance: *Initial compliance testing then annually when operating the combustion turbine. Annual opacity testing is required for fossil fuel steam generators, per F.A.C. Rule 62-296.405 (1) (a)].*	
5. Visible Emissions Comment (limit to 200 characters): *40 CFR Section 60.42a (b) describes the VE requirements which primarily apply because of the duct burner and because there is a common exhaust.*	

Visible Emissions Limitation: Visible Emissions Limitation ___2___ of ___2___

1. Visible Emissions Subtype: *VE10*	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: *10 % (6 min. avg.)* Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: *Initial compliance testing then annually when operating combustion turbine [annual opacity testing is required for fossil fuel steam generators, per F.A.C. Rule 62-296.405 (1) (a)].*	
5. Visible Emissions Comment (limit to 200 characters): *A 10% VE requirement was placed in the PSD permit to ensure compliance with PM emissions criteria. This requirement is more stringent that the otherwise applicable 20% requirement.*	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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: P*rovided in the NOx Monitoring Plan, attached at Appendix D* Manufacturer: Model Number: Serial Number:	
5. Installation Date: *Prior to start of operation.*	6. Performance Specification Test Date: *Within 90 days of start of commercial operation.*
7. Continuous Monitor Comment (limit to 200 characters): *NO_x monitoring is required under the Acid Rain rules of 40 CFR Part 72 and 75 for the combustion turbine and is specified in the PSD permit*	

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

<u>Supplemental Requirements</u>

1. Process Flow Diagram [X] Attached, Document ID:_*Appendix A*_[ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested *Natural Gas will only be fired. Analysis for fuel sulfur content will be performed after startup.*
3. Detailed Description of Control Equipment [X] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested *See Sections 2 and 5 of the report text*
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable *Will be provided after initial testing.*
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable *None Identified.*
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION (All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

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

4. Emissions Unit Identification Number: ID: *EU-0003*
[ ] No ID
[ ] ID Unknown

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

9. Emissions Unit Comment: (Limit to 500 Characters) *The cooling tower will be a multi-cell recirculating wet cooling tower. Cooling will provide for removal of reject heat from the steam cycle condenser associated with operation of the HRSG and 74 MW steam turbine*

Emissions Unit Control Equipment

A.

1. Control Equipment/Method Description (Limit to 200 characters per device or method): *Drift Eliminators*
2. Control Device or Method Code(s): *015*

B.

1. Control Equipment/Method Description (Limit to 200 characters per device or method): *NA*
2. Control Device or Method Code(s):

Emissions Unit Details

1. Initial Startup Date: *April 2002*
2. Long-term Reserve Shutdown Date: *Not Applicable*
3. Package Unit: *Cooling Tower* Manufacturer: *GEA* Model Number:
4. Generator Nameplate Rating: *Not Applicable*
5. Incinerator Information: *Not Applicable* Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

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

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram?		2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code:	6. Stack Height: feet		7. Exit Diameter: feet
8. Exit Temperature:	9. Actual Volumetric Flow Rate: acfm		10. Water Vapor:
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: East (km): North (km):			
14. Emission Point Comment (limit to 200 characters):			

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

Segment Description and Rate: Segment ___1__ of ___1__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): *Natural Gas Combustion for the Combustion Turbine.*			
2. Source Classification Code (SCC): *A282001000 Process Cooling Towers*		3. SCC Units: *1000 Gallons Water Circulated*	
4. Maximum Hourly Rate: *3,600,000 gallons per hour*	5. Maximum Annual Rate: *31,536 x 10^6 gallons per year*		6. Estimated Annual Activity Factor: *Not Applicable*
7. Maximum % Sulfur: *Negligible*	8. Maximum % Ash: *None*		9. Million Btu per SCC Unit: *N/A*
10. Segment Comment (limit to 200 characters):			

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	*015*		*WP*
PM10	*015*		*WP*

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited?
5. Range of Estimated Fugitive Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: Reference:		7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions ______ of ______

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

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___2___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

Visible Emissions Limitation: Visible Emissions Limitation ___2___ of ___2___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

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

Continuous Monitoring System: Continuous Monitor ___1__ of __1___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

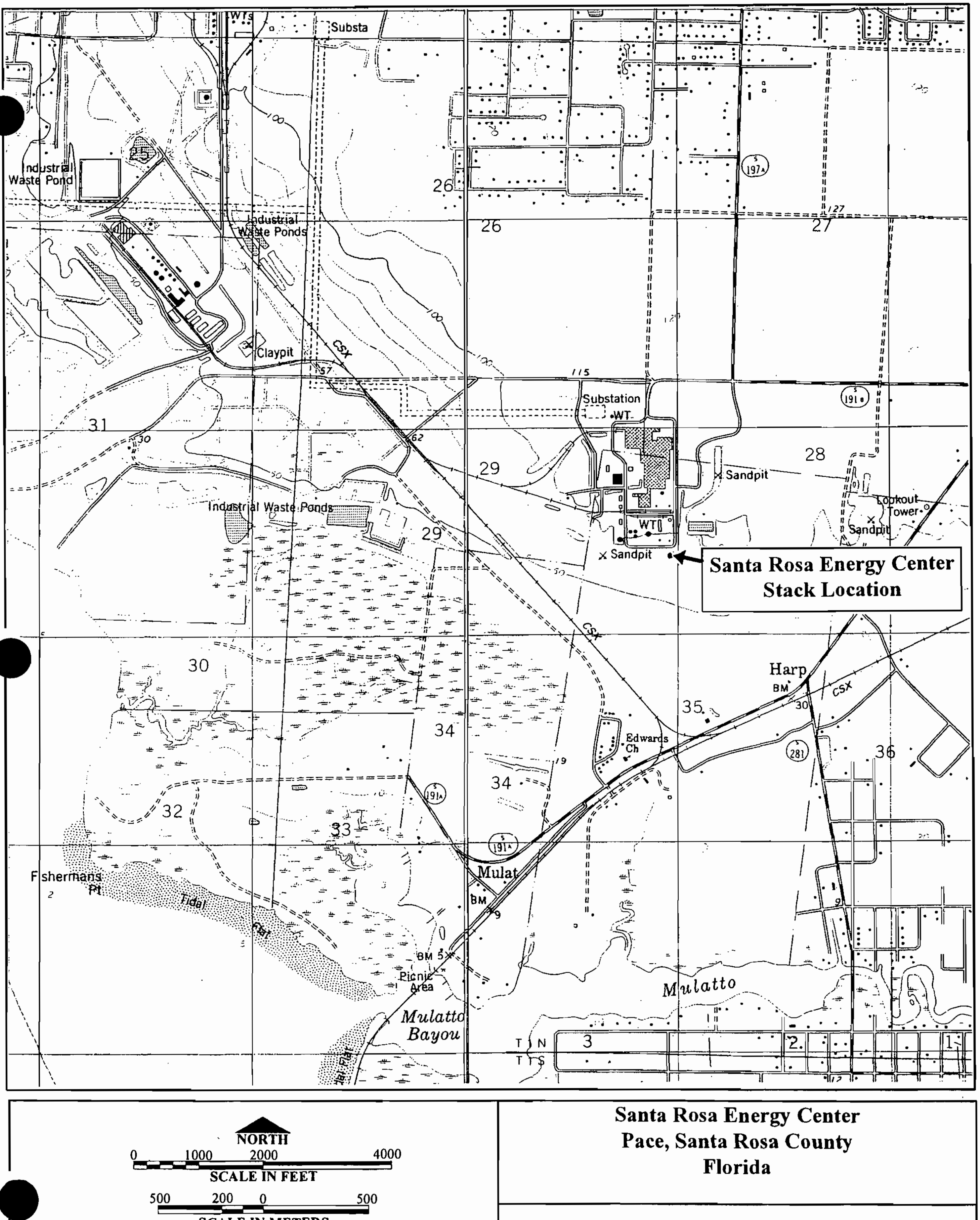
11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable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

APPENDIX A

AREA MAP

FACILITY LAYOUT

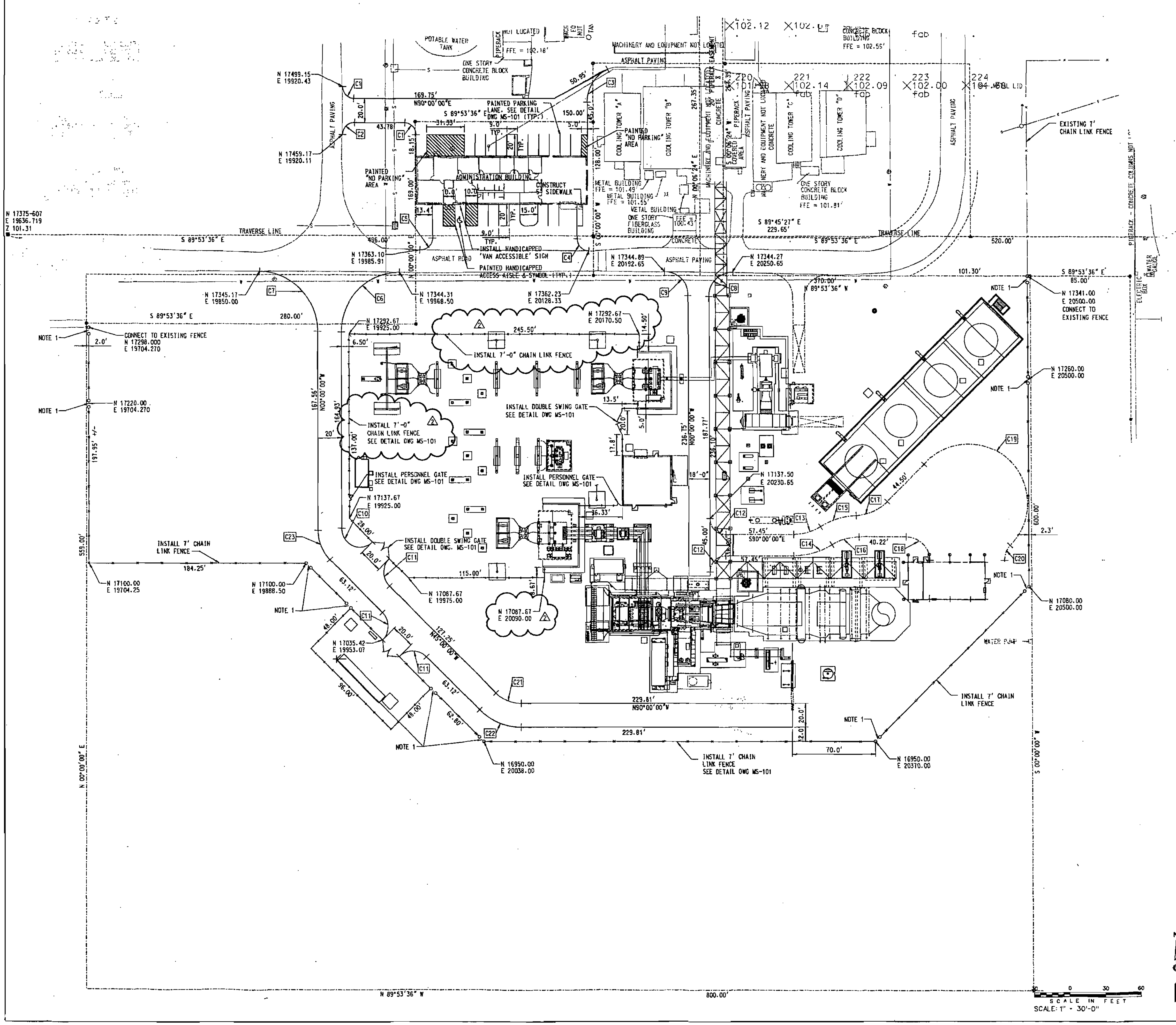
PROCESS FLOW DIAGRAM



SOURCE:
Base map adapted from USGS 7.5 minute series quadrangles (1:24,000) Milton South and Pace, dated 1978, PR 1987.

Santa Rosa Energy Center
Pace, Santa Rosa County
Florida

FACILITY LOCATION MAP



SITE ACREAGE:

LEASED AREA = 11.20 Ac
DEVELOPED AREA = 5.95 Ac
UNIMPROVED AREA = 4.38 Ac

SITE AREAS:

ASPHALT = 19,534 S.F.
AGGREGATE = 154,229 S.F.
TURF = 262,107 S.F.

BUILDING AREAS:

ADMINISTRATION BUILDING = 5,760 SQ. FT.
CHEMICAL FEED BUILDING = 2,080 SQ. FT.
ELECTRICAL BUILDING = 1,764 SQ. FT.

CURVE TABLE				
CURVE	LENGTH	RADIUS	DELTA	TAN
C1	15.25	10.00	87°23'00"	9.55
C2	16.16	10.00	92°37'00"	10.47
C3	33.89	30.00	64°43'04"	19.01
C4	15.64	10.00	89°37'48"	9.94
C5	16.20	10.00	92°49'34"	10.51
C6	78.54	50.00	90°00'00"	50.00
C7	77.04	50.00	88°16'51"	48.52
C8	31.88	20.00	91°19'56"	20.47
C9	31.33	20.00	89°46'05"	19.92
C10	36.87	15.40	137°07'13"	39.23
C11	25.53	16.25	90°00'00"	16.25
C12	21.21	13.50	90°00'00"	13.50
C13	23.70	42.00	32°20'04"	12.18
C14	33.86	60.00	32°20'04"	17.39
C15	31.75	60.00	30°19'24"	16.26
C16	23.94	42.00	32°39'41"	12.31
C17	29.78	40.00	42°39'43"	15.62
C18	31.42	20.00	90°00'00"	20.00
C19	160.17	49.62	184°57'27"	1146.13
C20	13.84	20.00	39°38'06"	7.21
C21	23.56	30.00	44°59'59"	12.43
C22	39.27	50.00	45°00'00"	20.71
C23	27.20'	35.40	44°00'44"	14.66

NOTES:

1. SEE FENCE ISOLATION DETAIL DWG. 20-131-MS-101

REV.	DESCRIPTION	PREP	CHK	DATE
2	ADD FENCE COORDS. CHANGED FENCE NOTES	[illegible]	[illegible]	8/27/01
1	ADD FENCE ISOLATION LOCATIONS	SMC	BAC	08-09-01
0	ISSUED FOR CONSTRUCTION	CEL	BAC	07-30-01

Bibb and associates
A KIEWIT COMPANY
8455 Lenexa Drive
Lenexa, Kansas 66214

GILBERT SOUTHERN CORP.

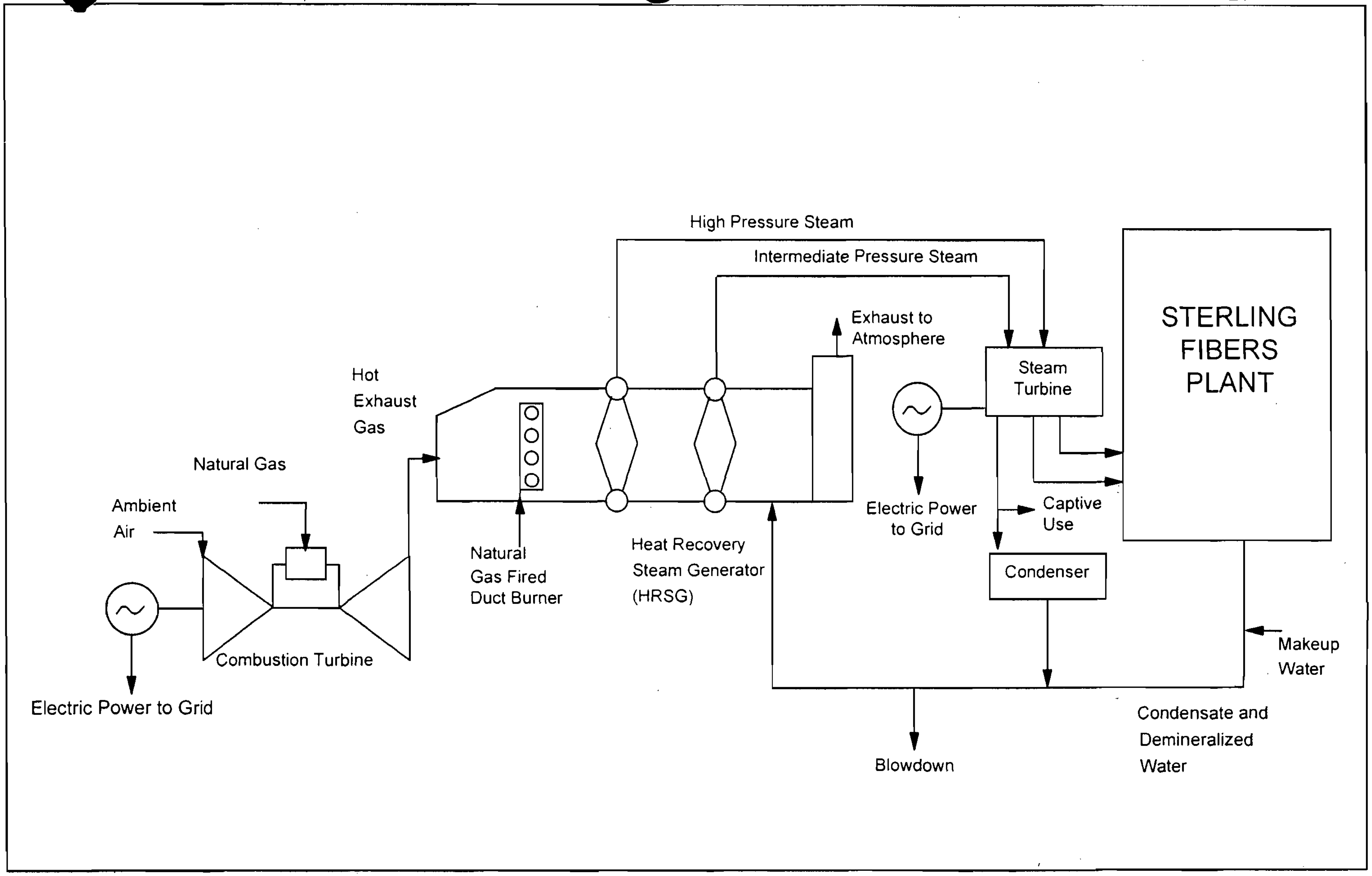
CALPINE

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

SITE PLAN

	by	date
DESIGNED	BAC	07/30/01
DRAWN	CEL	07/30/01
CHECKED	JLB	07/30/01
APPROVED	SMG	07/30/01

SHEET 1 of 1
DRAWING NUMBER 20-131-SP-101



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SANTA ROSA ENERGY CENTER
SIMPLIFIED PROCESS DIAGRAM

APPENDIX B

LIST OF INSIGNIFICANT ACTIVITIES

List of Insignificant Activities

In addition to the designated emissions units, Santa Rosa Energy Center operates equipment or work practices which produce insignificant emissions below the *deminimis* 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 chemicals storage
- Water treatment (reverse osmosis, demineralization, pH control, addition of anti-corrosion and anti-scaling agents, oil-water separation)
- Grounds and Lawn Maintenance

APPENDIX C

PSD PERMIT

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

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

Authorized Representative:

James Shield, Vice-President

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

Not in Title V Application

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.]

OK

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

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.]

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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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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.

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 <u>input</u> (lb NO_X/mmBtu). It is well below the revised Subpart Da <u>output</u>-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 501**FC** CTs Canceled GE CTs
Tallahassee, FL	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231**FA** 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 501F CTs
Sithe/IPP, NY	1012 MW CC CON	4.5 - NG	DLN & SCR	4 x160 MW GE **7FA** CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW GE **7FA** CTs
Barry, AL	800 MW CC CON	3.5 - NG (CT/DB)	DLN & SCR	3x170 MW GE **7FA** 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

<u>Combustion Controls</u>

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.

Selective Catalytic Combustion

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]

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:

A. A. Linero P.E.

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

12/2/98
Date:

Approved By:

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

12-4-98
Date:

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[10] City of Tallahassee. PSD/Site Certification Application. April, 1997.

[11] Florida DEP. Intent to Issue Permit. FPL Fort Myers Repowering Project. September, 1998.

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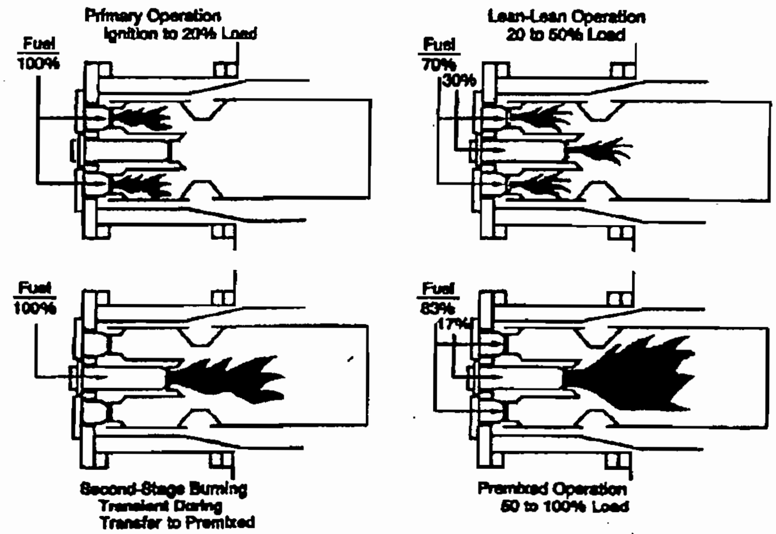
[15] Telecon. Schorr, M., GE, and Linero, A. A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.

[16] Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."

[17] General Electric. Combined Cycle Startup Curves. June 19, 1998.



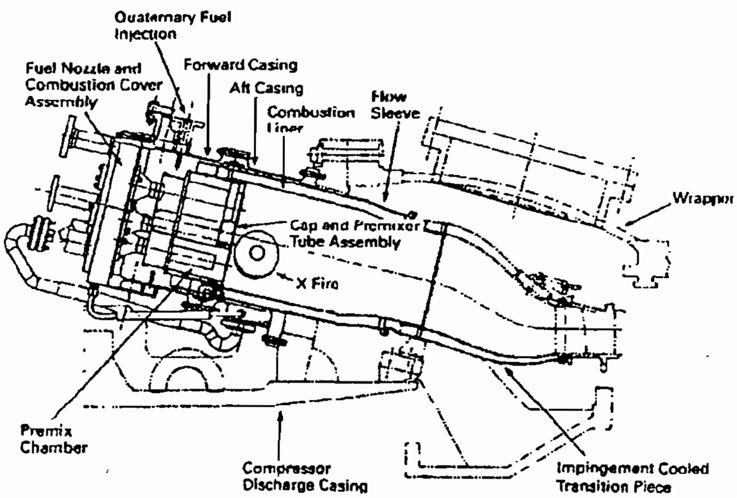


Figure 1 - Dry Low NOX Operating Modes - DLN-1

Cross Section of DLN-2.0

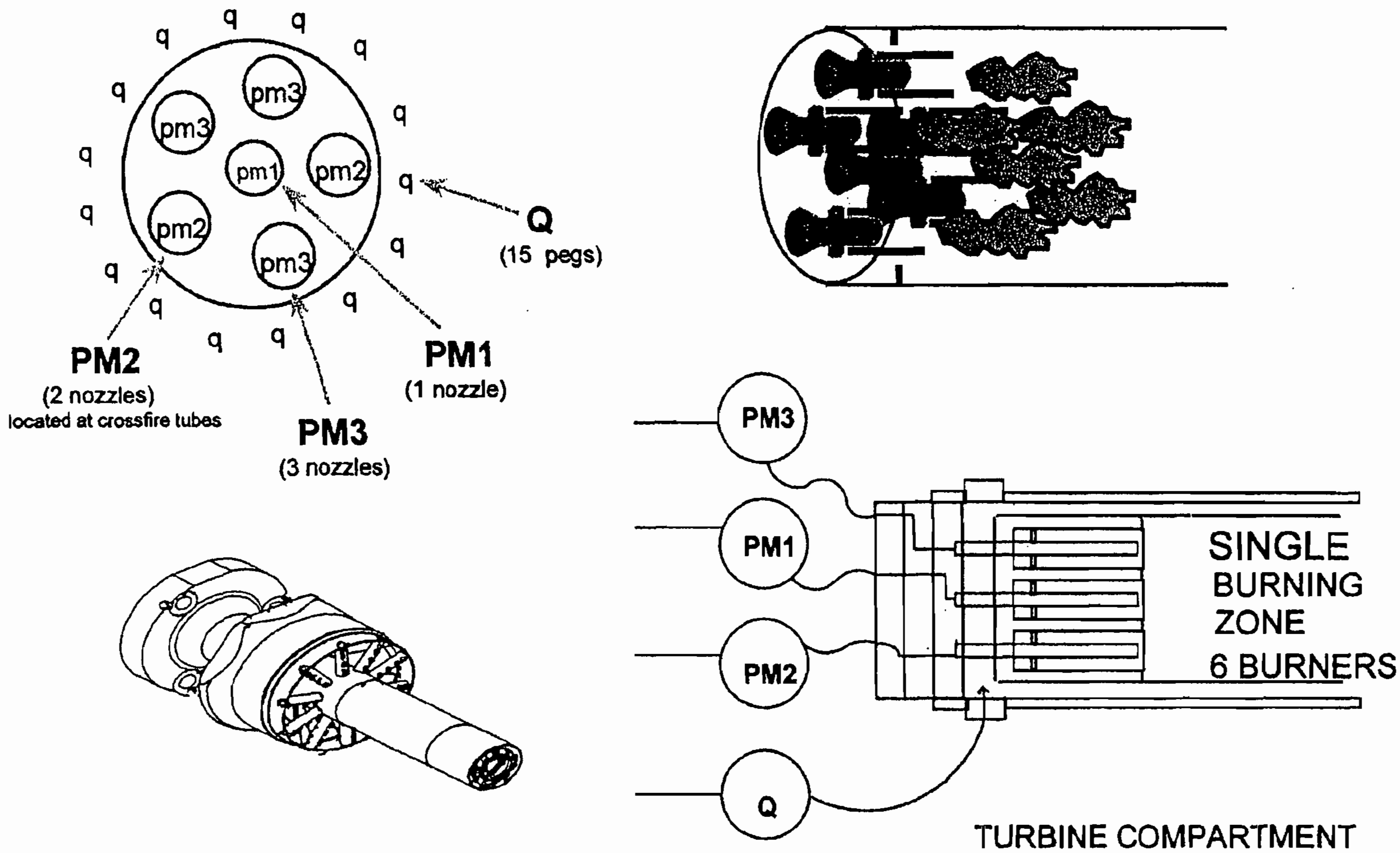


Figure 2 - GE DLN-2.6 Combustor and Nozzle Arrangement

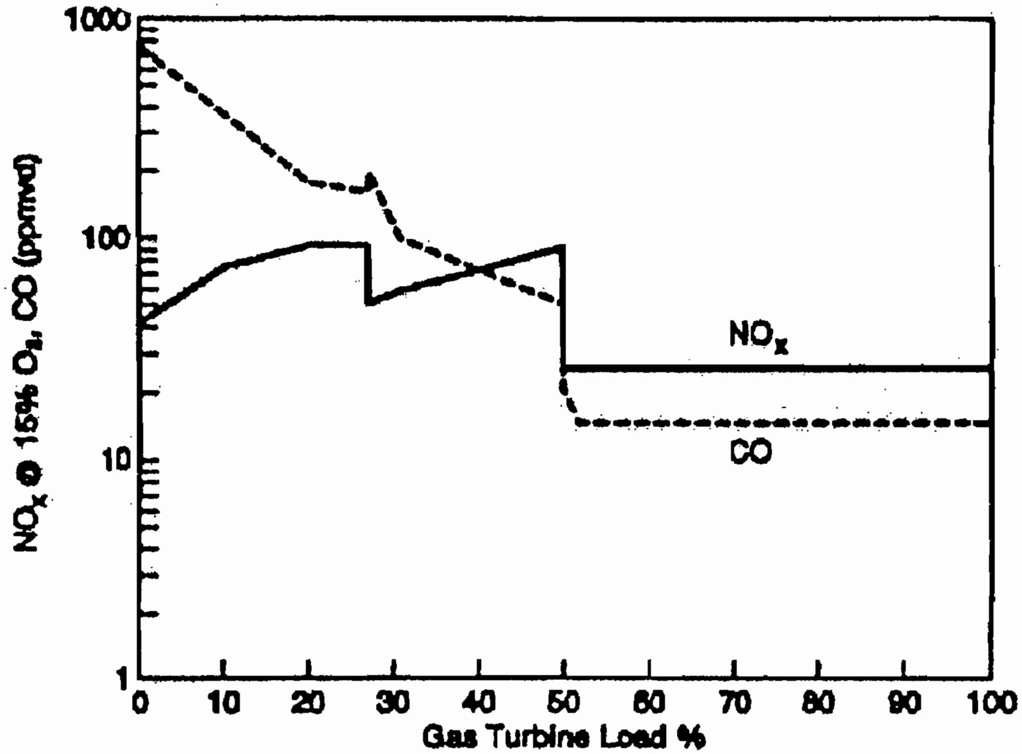


Figure 3 - Emissions Performance Curves for GE DLN-2 Combustors

Firing Natural gas in Dual Fuel GE 7FA Combustion Turbine

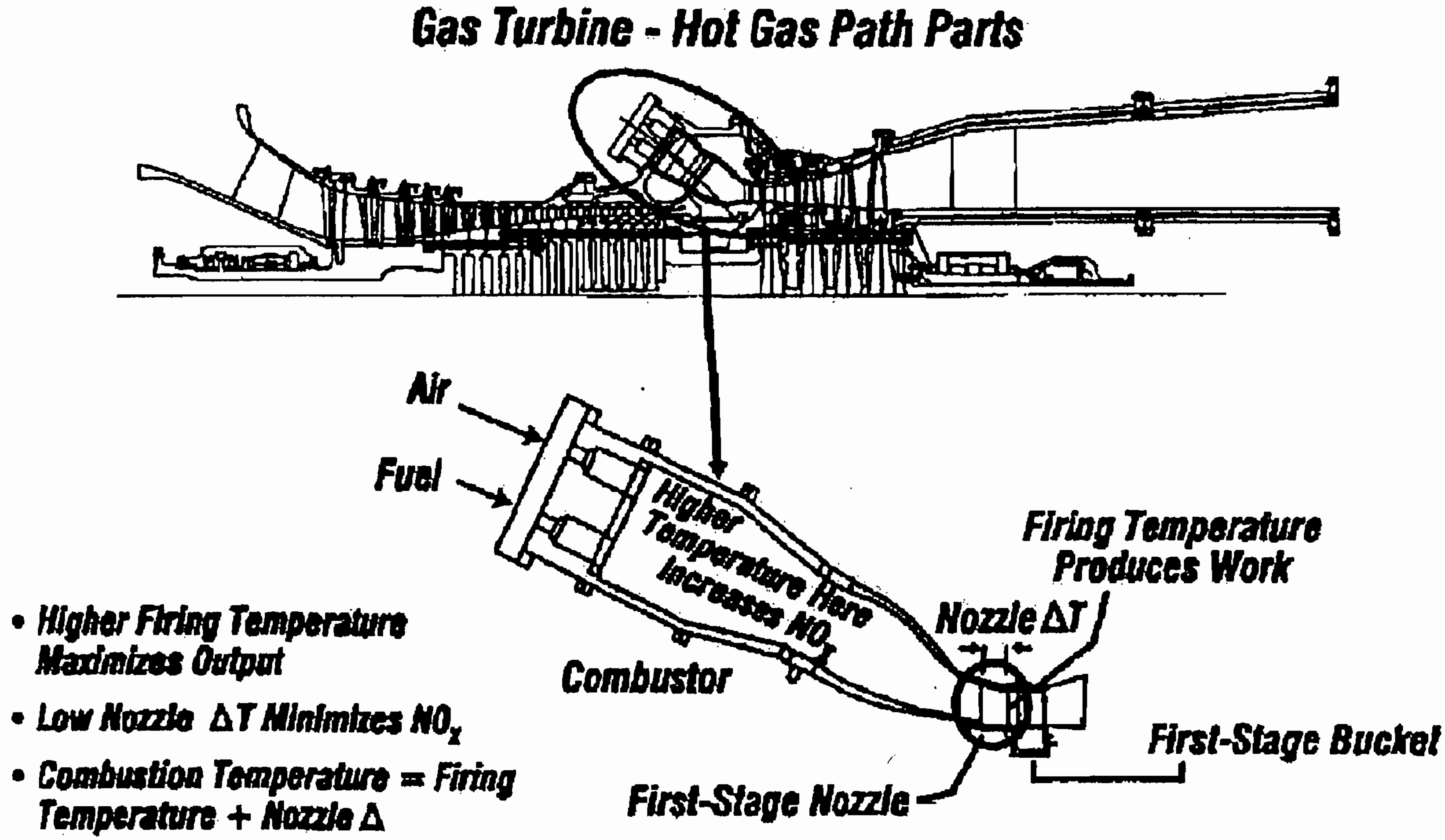


Figure 4 - Relation Between Flame Temperature and Firing Temperature

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.

APPENDIX D

COMBUSTION TURBINE NOx MONITORING PLAN

Work Order No. 12880.001.001

Combustion Turbine
NO_X Monitoring Plan
Santa Rosa Energy Center
Pace, Florida

Prepared For

GILBERT SOUTHERN CORP.
5003 Sterling Way
Pace, Florida 32571

Prepared By

ROY F. WESTON, INC.
1625 Pumphrey Ave.
Auburn, Alabama 36832-4303

6 March 2002

LIST OF CONTENTS

EDR Version 4.0 MONITORING PLAN FILE ON 3½" DISK - FILENAME
- SANTA ROSA MP 03-06-02.TXT
- SANTA ROSA MP 03-06-02.RTF
- SANTA ROSA MP EVALUATION 03-06-02.RTF

PRINTOUTS OF
- TEXT FILE
- CHECKING SOFTWARE EVALUATION
- MONITORING PLAN PRINTOUT

EXPECTED RECORD TYPES USED TO REPORT QUARTERLY DATA

DIAGRAM OF CEMS LOCATION AND COMPONENTS

UNIT NOTES

Note: Software Disk Submitted with Monitoring Plan Has Been Omitted

```
10005524222002V2.1
102SANTA ROSA ENERGY                          1130168        COGENERATION        4911FL113 303358 870654
504CT-1  CT  1780.020020415         200   92 283   0
505CT-1  ARP        P2Q 20020423          FL
506CT-1  CT-1  CT-1 CT-1 2000 55242  55242
507CT-1  20022002P100.02003P100.02004P100.0100.0GF3PR
510CT-1  DAS100AGAS P DAHS   CONTEC SYSTEMS                                                        20020423
510CT-1  GAS100AGAS P GFFMORFCONTROL CENTER, LLC      N/A            3007406                       20020423
510CT-1  DAS200ANOX P DAHS   CONTEC SYSTEMS                                                        20020423
510CT-1  NOX200ANOX P NOX EXTROSEMOUNT                CLD-NGA2000    U1004341                      20020423
510CT-1  O2D200ANOX P O2D EXTFISHER ANALYTICAL        MLT-NGA2000    W0342996                      20020423
510CT-1  DAS300AO2  P DAHS   CONTEC SYSTEMS                                                        20020423
510CT-1  O2D300AO2  P O2D EXTFISHER ANALYTICAL        MLT-NGA2000    W0342996                      20020423
520CT-1  A101HI  D-6  HI=S#(Gas-100)*GCVgas/1**6  Where: HI=heat input PNG, MMBtu/hr; S#(Gas-100)=measured PNG flow rate, HSCF/hr; GCVgas=heat content PNG, Btu/HSCF; 1**6= conversion to MMBtu
520CT-1  A301SO2 D-5  SO2g=F#(101)*0.0006   Where:   SO2g=SO2 mass emissions from PNG, lb/hr; F#(101)=Heat Input PNG, MMBtu/hr; 0.0006=default SO2 emission factor for PNG, lb/MMBtu
520CT-1  A401NOX 19-1 NOxrate=K*Cd*S#(NOx-200)*8710*20.9/(20.9-S#(O2D-300))  Where:   NOxrate=NOx emission rate, lb/MMBtu; K=calc constant, 1.19e-7; S#(NOx-200)=NOx conc, ppmvd; 8710=F-factor PNG; S#(O2D-300)=O2 conc, %
520CT-1  A501CO2 G-4  CO2g=(Fc*F#(101)*1/385*44)/2000  Where:  CO2g=CO2 mass emission PNG, ton/hr; Fc=carbon dioxide F-factor PNG, 1040 scf/MMBtu; F#(101)=heat input PNG, MMBtu/hr; 1/385=1/molar  volume; 44=molecular weight
530CT-1  NOX HOL        9.000 0.730       18.000       20.000PPM    02042300
530CT-1  O2  H         21.000             25.000       25.000%      02042300
535CT-1  MW   241
536CT-1     168    84H,MH 20020423
540CT-1  100GAS PNG   18292.6HSCF URVAGA3                A
585CT-1  CO2 GFF       PNGPSPTS  20020423
585CT-1  HI  GFF       PNGPSPTS  20020423
585CT-1  NOXRCEM       NFSPSPTS  20020423
585CT-1  OP  EXP       PNGPSPTS  20020423
585CT-1  SO2 GFF       PNGPSPTS  20020423
586CT-1  NOX DLNB  PO2002042320020423
587CT-1  PNG20020423        P
```

FACILITY INFORMATION (RT 102)

ORIS Code/Facility ID: 55242
EPA FINDS ID:
EPA AIRS ID:
State ID: 1130168

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

County Code: 113
County Name: SANTA ROSA
Source Category/Type: COGENERATION

Primary SIC Code/Description: 4911 Electric Services

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
CT-1	CT-1	CT	1780.0	04/15/2002	/ /	200	92	283	

Boiler Type Codes: CT - 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	04/23/2002		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/ORISPL Number
CT-1	CT-1	CT-1	CT-1	2000		55242

FUEL USAGE QUALIFICATION INFORMATION (RT 507)

Unit ID	Year of Qualification	Capacity or Gas Usage: 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

Gas Qualifying Codes: 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						
Status	System ID	Parameter	P/B	First Reporting Date	Last Reporting Date	Component ID	Status	Component Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	100	GAS	P	04/23/2002	/ /	DAS	A	DAHS		CONTEC SYSTEMS		
						GAS	A	GFFM	ORF	CONTROL CENTER, LLC	N/A	3007406
A	200	NOX	P	04/23/2002	/ /	DAS	A	DAHS		CONTEC SYSTEMS		
						NOX	A	NOX	EXT	ROSEMOUNT	CLD-NGA2000	U1004341
						O2D	A	O2D	EXT	FISHER ANALYTICAL	MLT-NGA2000	W0342996
A	300	O2	P	04/23/2002	/ /	DAS	A	DAHS		CONTEC SYSTEMS		
						O2D	A	O2D	EXT	FISHER ANALYTICAL	MLT-NGA2000	W0342996

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

Unit/Stack/Pipe ID: CT-1

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	101	HI	D-6	HI=S#(Gas-100)*GCVgas/1**6 Where: HI=heat input PNG, MMBtu/hr; S#(Gas-100)=measured PNG flow rate, HSCF/hr; GCVgas=heat content PNG, Btu/HSCF; 1**6= conversion to MMBtu
A	301	SO2	D-5	SO2g=F#(101)*0.0006 Where: SO2g=SO2 mass emissions from PNG, lb/hr; F#(101)=Heat Input PNG, MMBtu/hr; 0.0006=default SO2 emission factor for PNG, lb/MMBtu
A	401	NOX	19-1	NOxrate=K*Cd*S#(NOx-200)*8710*20.9/(20.9-S#(O2D-300)) Where: NOxrate=NOx emission rate, lb/MMBtu; K=calc constant, 1.19e-7; S#(NOx-200)=NOx conc, ppmvd; 8710=F-factor PNG; S#(O2D-300)=O2 conc, %
A	501	CO2	G-4	CO2g=(Fc*F#(101)*1/385*44)/2000 Where: CO2g=CO2 mass emission PNG, ton/hr; Fc=carbon dioxide F-factor PNG, 1040 scf/MMBtu; F#(101)=heat input PNG, MMBtu/hr; 1/385=1/molar volume; 44=molecular weight

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	Scale	Meth- od	MPC/ MEC/ MPF	Max. NOx Rate	Span Value	Full-Scale Range	Units of Measure	Eff. Date and Hour	Inactive Date & Hour	Dual Spans Req.	Def. High Range Value
CT-1	NOX	H	OL	9.000	0.730	18	20	PPM	04/23/2002 00	/ /		
	O2	H		21.000		25.0	25.0	%	04/23/2002 00	/ /		

Parameter Codes: NOX - NOx concentration, O2 - Oxygen
Scale Codes: H - High
Method Codes: OL - Other limit
Units of Measure Codes: % - Percent, PPM - Parts per million

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

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Single Load RATA Testing Only
CT-1	MW	241	

RANGE OF OPERATION, NORMAL LOAD AND LOAD USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Load Levels	Designated Normal Load	Second Designated Normal Load	Activation Date	Deactivation Date
CT-1	168	84	H,M	H		04/23/2002	/ /

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	100	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	04/23/2002	/ /
	HI	GFF	PNG	P	SPTS	04/23/2002	/ /
	NOXR	CEM	NFS	P	SPTS	04/23/2002	/ /
	OP	EXP	PNG	P	SPTS	04/23/2002	/ /
	SO2	GFF	PNG	P	SPTS	04/23/2002	/ /

Parameter Codes: CO2 - Carbon Dioxide, HI - Heat Input, NOXR - NOx Emission Rate, OP - Opacity, SO2 - Sulfur Dioxide
Fuel Type Codes: NFS - Non-fuel specific, PNG - Pipeline natural gas
Methodology Codes: CEM - Continuous emission monitoring, EXP - Exempted, 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	04/23/2002	04/23/2002	/ /	

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	04/23/2002	/ /			

Fuel Classification Codes: PNG - Pipeline natural gas

ORIS Code: 55242 State: FL
Facility Name: SANTA ROSA ENERGY County: SANTA ROSA

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=

EVALUATION OF MONITORING PLAN DATA FOR UNIT CT-1

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this unit.

ACID RAIN PROGRAM EDR RECORDS USED TO REPORT QUARTERLY DATA

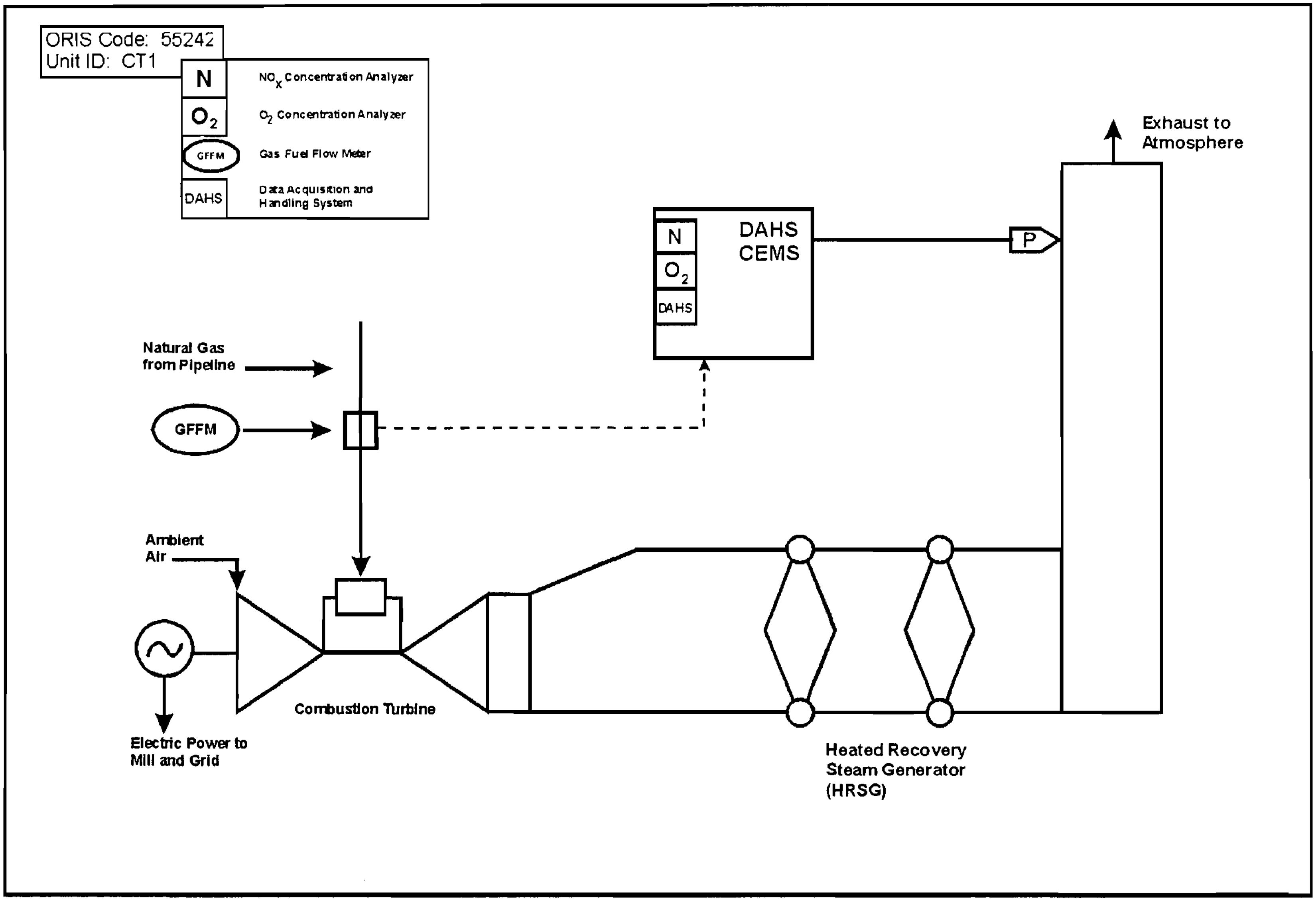
Type of Source: -Part 75 Gas-fired Combustion Turbine
NO_x and O_2 Concentration Monitoring Systems

Record Type	Description
Facility Data	
RT 100	Source Identification
RT 102	Facility Monitoring Plan Data
Unit Data	
RT 201	Hourly NO_x Concentration
RT 201	Hourly O_2 Concentration
RT 230	Daily Calibrations of NO_x Analyzer and O_2 Analyzer
RT 300	Hourly Operating Data
RT 301	Quarterly Cumulative Emission Data
RT 303	Gas Volumetric Flow Rate
RT 314	SO_2 Emission Rate from Gas
RT 313	NO_X Emission Rate
RT 320	CO_2 Mass Emission Rate
RT 504	Unit Information
RT 505	Indicator Record for NO_x Budget Program
RT 506	EIA Cross-reference Information
RT 507	Fuel Usage Data for Gas-fired Unit
RT 510	Monitoring Systems Records Identifying NOx and Flow Systems
RT 520	Formulas for Calculating NO_x Mass Emission Rate Emissions
RT 530	Span Table including Monitor Ranges
RT 535	Stack Maximum Load Definition
RT 536	Range of Operation
RT 540	Fuel Flowmeter Data Gas
RT 585	NO_x Monitoring Methodology Information
RT 586	Control Equipment Information
RT 587	Unit Category by Fuel Type
RT 587	Unit Fuel Type

RT 600	Seven-day Drift Test Results
RT 601	Quarterly Linearity Test Data
RT 602	Quarterly Linearity Test Results
RT 610	Annual RATA Test Data
RT 611	Annual RATA Test Results
RT 621	Cycle Time Test
RT 627	Fuel Flowmeter Accuracy Test

Certification Data

RT 900	Part 75 Certification
RT 901	Part 72 Certification
RT 910	Cover Letter
RT 920	Cover Letter Test
RT 920	Certification Signature
RT 999	Contact Person Name and Phone Number



SANTA ROSA ENERGY CENTER
SIMPLIFIED PROCESS DIAGRAM

Notes about submittal and/or unit:

1) Maximum fuel flow for gas fuel flow meter (GFFM) calculated from maximum flow rate provided on meter certification (lb/sec).

2) Default values from Part 75 are used as NO_X analyzer range provided by CEMS manufacturer/Gilbert.

APPENDIX E

TITLE IV (ACID RAIN) PERMIT APPLICATION

Santa Rosa Energy LLC
650 Dundee Road
Suite 350
Northbrook, Illinois
60062

tel 847 559 9800
fax 847 559 1805

www.skygen.com

skygen

January 28, 2000
Letter No. 64

Mr. Thomas Cascio
Engineer IV
Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Mail Station 55-05
Tallahassee, FL 32399-2400

Dear Mr. Cascio:

In accordance with The United States Environmental Protection Agency Acid Rain Program, we are submitting the forms necessary to obtain an Acid Rain Permit for the Santa Rosa Energy Center located in Pace, Florida. Enclosed are the Certificate of Representation and Phase II Permit Application forms. Also enclosed is proof that the Public Notice of Designation of Representation was printed in the local newspaper, The Santa Rosa Press Gazette.

If you have any questions or need additional information, please feel free to contact me at 847-559-9800 extension 311.

Sincerely,

Santa Rosa Energy LLC
by its Managing Member
SkyGen Energy LLC

Dave Plauck
Project Manager

Encl.

File: ENVR-ARP

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Certificate of Representation

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

This submission is: [X] New [ ] Revised (revised submissions must be completed in full; see instructions)

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

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

Plant Name	State	ORIS Code
Santa Rosa Energy Center	FL	55242

STEP 2
Enter requested information for the designated representative.

Name	David Plauck
Address	650 Dundee Road Suite 350 Northbrook, IL 60062
Phone Number	(847) 559-9800 ext. 311
Fax Number	(847) 559-1805
E-mail address (if available)	dplauck@skygen.com

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

Name	
Phone Number	
Fax Number	
E-mail address (if available)	

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

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

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

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

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

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

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

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

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

Santa Rosa Energy Center
Plant Name (from Step 1)

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

Signature (designated representative)	Date 1/14/2000
Signature (alternate designated representative)	Date

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

Name: Santa Rosa Energy LLC					[X] Owner	[X] Operator
ID# COG01	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

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

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

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

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#	b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c Compliance Plan 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.

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

Santa Rosa Energy Center

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,

Santa Rosa Energy Center

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

The Santa Rosa
Press Gazette
PUBLISHED BI-WEEKLY
Milton, Santa Rosa County, Florida

STATE OF FLORIDA

County of Santa Rosa

Before the undersigned authority personally appeared

Susan Holley

who on oath says that he is Cashier
of the Press Gazette, a bi-weekly newspaper published at Milton in Santa Rosa County, Florida; that the attached copy of

advertisement being a Public Notice of Designation of Representation

in the matter of Santa Rosa Energy, LLC

in the ________________ court,
was published in said newspaper in the issues of:

January 19 A.D., 2000

A.D., 20___

A.D., 20___

A.D., 20___

A.D., 20___

A.D., 20___

Affiant further says that the Press Gazette is a newspaper published at Milton in said Santa Rosa County, Florida and that said newspaper has heretofore been continuously published in said Santa Rosa County, Florida, each week and has been entered as second class mail matter at the post office in Milton in Santa Rosa County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

I (SWEAR) (AFFIRM) that the above information is true and correct to the best of my knowledge.

Susan Holley
(Signature of Applicant)

Sworn to and subscribed before me this

19 day of January 2000

Carolyn V. Barnes
(Signature of Notary Public-State of Florida)

(Print, Type or Stamp Commissioned Name of Notary Public)

CAROLYN V. BARNES
MY COMMISSION # CC 764308
EXPIRES: November 12, 2002
Bonded Thru Notary Public Underwriters

Personally known ✓ OR Produced Identification_______

Type of Identification Produced: _______

PUBLIC NOTICE OF DESIGNATION OF REPRESENTATION

As per 40 CFR 72.24, please take notice that an agreement has been reached with Santa Rosa LLC that I, David Plauck, have been selected to be the designated representative for matters related to the Acid Rain Program for Santa Rosa Energy LLC, which will be owner and operator of a planned combined cycle cogeneration facility to be constructed in Pace, FL.

Written public comments may be sent to Thomas Cascio at Florida Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, FL 232992400. Santa Rosa Energy LLC can be reached at:

Santa Rosa Energy LLC
650 Dundee Road
Suite 350
Northbrook, IL 60062
Telephone: (847) 559-9800

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APPENDIX F

CALCULATION OF HAZARDOUS AIR POLLUTANT EMISSIONS

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 Pollutant 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.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 7, 2000

Mr. David Plauck
Project Manager
Santa Rosa Energy LLC
650 Dundee Road
Suite 350
Northbrook, Illinois 60062

Dear Mr. Plauck:

Re: Acid Rain Phase II Permit Application for the Santa Rosa Energy Center
ORIS Code: 55242

Thank you for your recent submission of the referenced application for this facility. We have reviewed the material and deem your application complete.

If you have any questions, please contact Tom Cascio at 850/921-9526.

Sincerely,

Scott M. Sheplak, P.E.
Administrator
Title V Program

cc: Jenny Jachim, U.S. EPA, Region 4