PSD PERMIT APPLICATION
FOR PROPOSED COGENERATION FACILITY

SANTA ROSA ENERGY CENTER

Submitted To:

BUREAU OF AIR REGULATION
DIVISION OF AIR RESOURCE MANAGEMENT
FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
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1. INTRODUCTION

Santa Rosa Energy LLC, a subsidiary of Polsky Energy Corporation (PEC) of Northbrook, Illinois, is proposing to install a combustion turbine combined cycle cogeneration facility at the Sterling Fibers Inc. (Sterling Fibers), Plant in Pace, Florida. The cogeneration facility, known as the Santa Rosa Energy Center, will be located within the Sterling Fibers Plant boundary and will also provide steam and electricity to Sterling Fibers and electricity to the electric utility grid.

The Santa Rosa Energy Center will allow Sterling Fibers to significantly reduce the operation of their existing boilers by utilizing the boilers for stand-by and back-up operation only When the Santa Rosa Energy Center is operating, the Sterling Fiber boilers will normally be off-line. Although the Sterling Fiber boilers will continue to be permitted under existing permits and will remain in an operationally ready state, the combined effect will be a significant reduction in NO_x emissions.

The proposed cogeneration facility will consist of a combustion turbine generator, a heat recovery steam generator (HRSG) equipped with a duct burner, a steam turbine generator (<75 MWe), and associated auxiliary equipment. The combustion turbine and the duct burner will fire only natural gas. The combustion turbine will supply electricity to both Sterling Fibers and the electric utility grid. Steam from the HRSG will be sent to the steam turbine for electric generation and to Sterling Fibers for process use and for minor captive uses. The combustion turbine and HRSG will operate simultaneously or not at all.

The equipment will be highly energy efficient and utilize a clean fuel. The combustion turbine will include an advanced Dry Low Nitrogen Oxides (NO_x) Combustor to maximize combustion efficiency while minimizing NO_x, carbon monoxide (CO), and volatile organic compounds (VOC) emissions. The duct burner will be equipped with a low NO_x burner.

This permit application has been prepared to fulfill Federal and Florida Department of Environmental Protection (FDEP) air permitting requirements.

1.1 APPLICATION ORGANIZATION

The permit application presents the required information for the proposed Santa Rosa Energy Center. Included in the application are detailed specifications and operating conditions for the combustion turbine and heat recovery steam generator along with expected maximum pollutant emission rates from the system. This permit application is organized into the following sections:

- Section 2 provides a description of the proposed cogeneration facility.
- Section 3 provides an emissions inventory for the proposed cogeneration facility. Additional documentation describing the estimation methods and calculations is provided in Appendix B.
- Section 4 provides a summary of the potentially applicable federal and State of Florida air quality rules.
- Section 5 provides a Best Available Control Technology (BACT) analysis as required by PSD regulations.
- Section 6 provides a summary of potential air quality impacts from the project.
- Appendix A provides the applicable FDEP permit application forms.
- Appendix B provides sample calculations for proposed emissions from the cogeneration system.
- Appendix C provides backup information and modeling output data from the air quality dispersion modeling analysis conducted as part of this project.
- Appendix D provides vendor information for some of the proposed cogeneration project equipment.

1.2 APPLICATION SUMMARY

The proposed Santa Rosa Energy Center will meet applicable Federal and State of Florida air quality regulatory requirements. The proposed facility will be subject to New Source Performance Standards (NSPS) Subparts A - General Provisions, Da - Electric Utility Steam Generating Units, and GG- Stationary Combustion Turbines, and Prevention of Significant Deterioration (PSD) regulations which require BACT for those pollutants emitted in PSD significant amounts and compliance with the Ambient Air Quality Standards (AAQS) and PSD increments. In addition, State of Florida regulations (Chapters 62-296) also apply to the proposed facility and certain requirements for emissions of particulate matter (PM), sulfur dioxide (SO_2), NO_x, and visible emissions (VE).

Best Available Control Technology for the Santa Rosa Facility consists of the following emission limitations for criteria pollutants:

- PM/PM_{10}, VOC, and CO - good combustion practices and clean burning fuels.
- NO_x - good combustion practices and clean burning fuels plus use of Dry Low NO_x Combustor to maintain emissions at no greater than 9 parts per million by volume, dry (ppmvd) (corrected to 15% O_2) for normal operation, 12 ppmvd (corrected to 15% O_2) for the power augmentation mode.

Based on the implementation of BACT, the maximum facility-wide air emissions inventory is as shown in Table 1-1. An air quality analysis was completed for PM/PM_{10}, NO_x, and CO. The predicted ambient air concentrations are all below PSD significance levels.

Table 1-1

Proposed Santa Rosa Energy Center
Significant PSD Pollutants

Pollutant	Facility Emission Rate (ton/yr) [A]	Significant Emission Rates (ton/yr) [B]	PSD Significant
Particulate Matter	55	25	Yes
PM_{10}	55	15	Yes
Sulfur Dioxide	7	40	No
Nitrogen Oxides	508	40	Yes
Non-methane Volatile Organic Compounds	45	40	Yes
Carbon Monoxide	347	100	Yes
Lead	0.0008	0.6	No
Mercury	0.0004	0.1 [c]	No
Beryllium	0.00002	0.0004 [c]	No

a Emissions rates do not include emissions from startup, shutdown, and malfunctions.

b From US EPA PSD regulations 40 CFR 52.21 (b)(23)(i)

c Title III of the Clean Air Act Amendments of 1990 added a new Section 112(b)(6) that excludes these hazardous air pollutants listed in Section 112(b)(6) of the revised Act from Federal PSD requirements. Current EPA policy (New Source Review Program Transitional Guidance, March 11, 1991) clarifies that States with approved PSD programs may continue to regulate these pollutants under State PSD regulations.

2. PROJECT DESCRIPTION

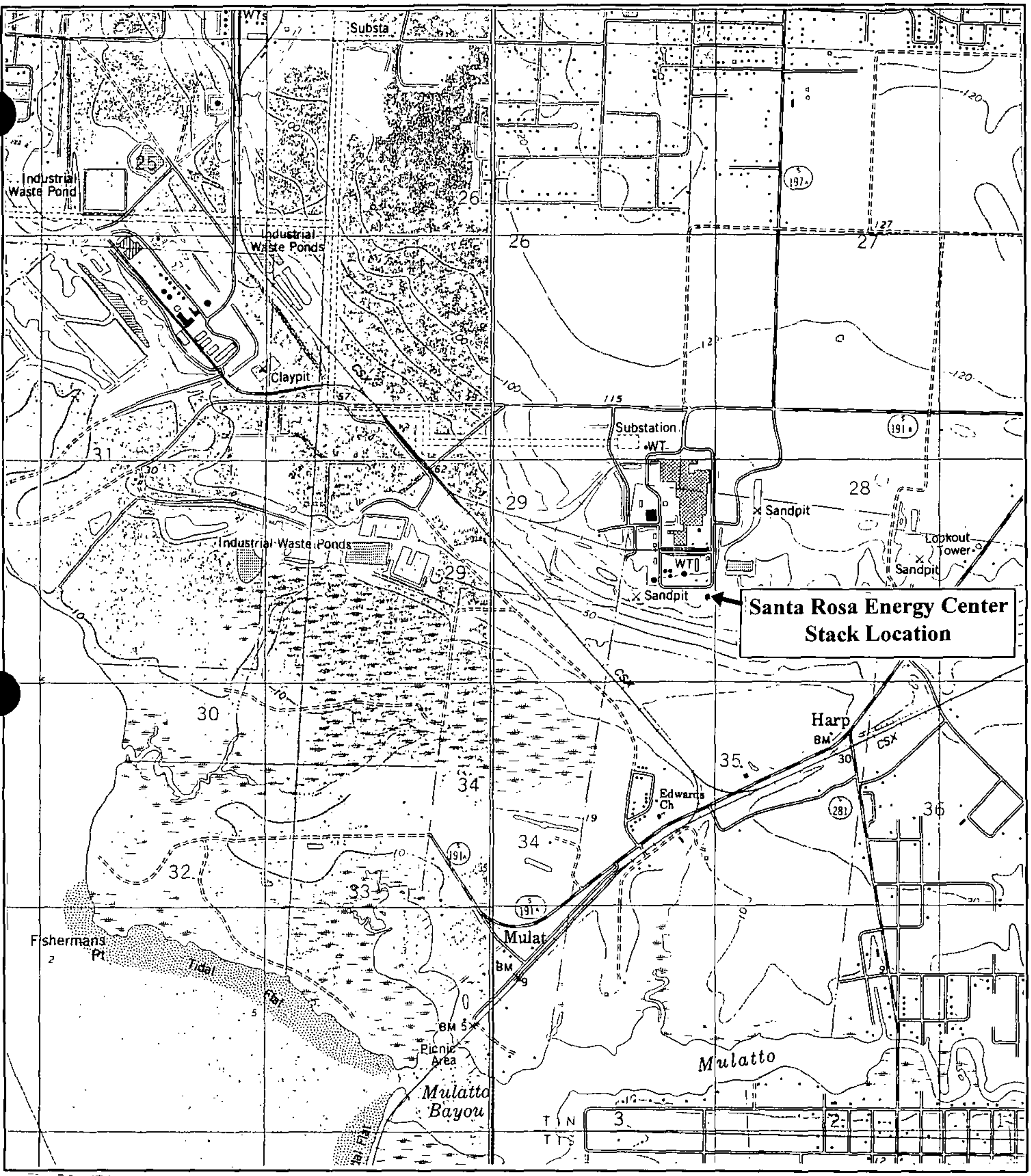
2.1 FACILITY LOCATION

Santa Rosa Energy LLC, a subsidiary of Polsky Energy Corporation of Northbrook, Illinois, is submitting this air permit application for installation of a cogeneration facility to supply energy in the form of steam and electricity to Sterling Fibers in Santa Rosa County, Florida. The Sterling Fibers plant is located in Pace, Florida. The plant location is depicted on a section of a United States Geological Survey (USGS) quadrangle in Figure 2-1. Electricity will also be provided to the electricity grid. The Santa Rosa Energy LLC will lease property from Sterling Fibers and the location of the cogeneration facility will be within the Sterling Fibers plant boundary as presented in Figure 2-2.

2.2 DESCRIPTION OF PROPOSED COGENERATION FACILITY

The primary components of the proposed cogeneration system will be a combustion turbine, a heat recovery steam generator (HRSG) equipped with a duct burner, and a steam turbine. Figure 2-3 provides a simplified process diagram. The combustion turbine will be a General Electric Frame 7F design or equivalent with an electric generation capacity of approximately 168 megawatts (MW) at 100% and at an average ambient temperature of 68°F and 60% relative humidity. The combustion turbine will be fired with natural gas. The combustion turbine will be equipped with a Dry Low NO_x Combustor for natural gas firing to limit NO_x emissions to 9 ppmvd at 15% O_2 under normal operating conditions.

The HRSG will be a triple pressure unit providing high pressure steam and intermediate steam to the steam turbine. Steam will be extracted from the steam turbine at lower pressures to provide process steam to Sterling Fibers. Low pressure steam will be used within the cogeneration facility primarily for the HRSG deaerator.



NORTH

0 1000 2000 4000

SCALE IN FEET

500 200 0 500

SCALE IN METERS

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

FIGURE 2-1
FACILITY LOCATION MAP

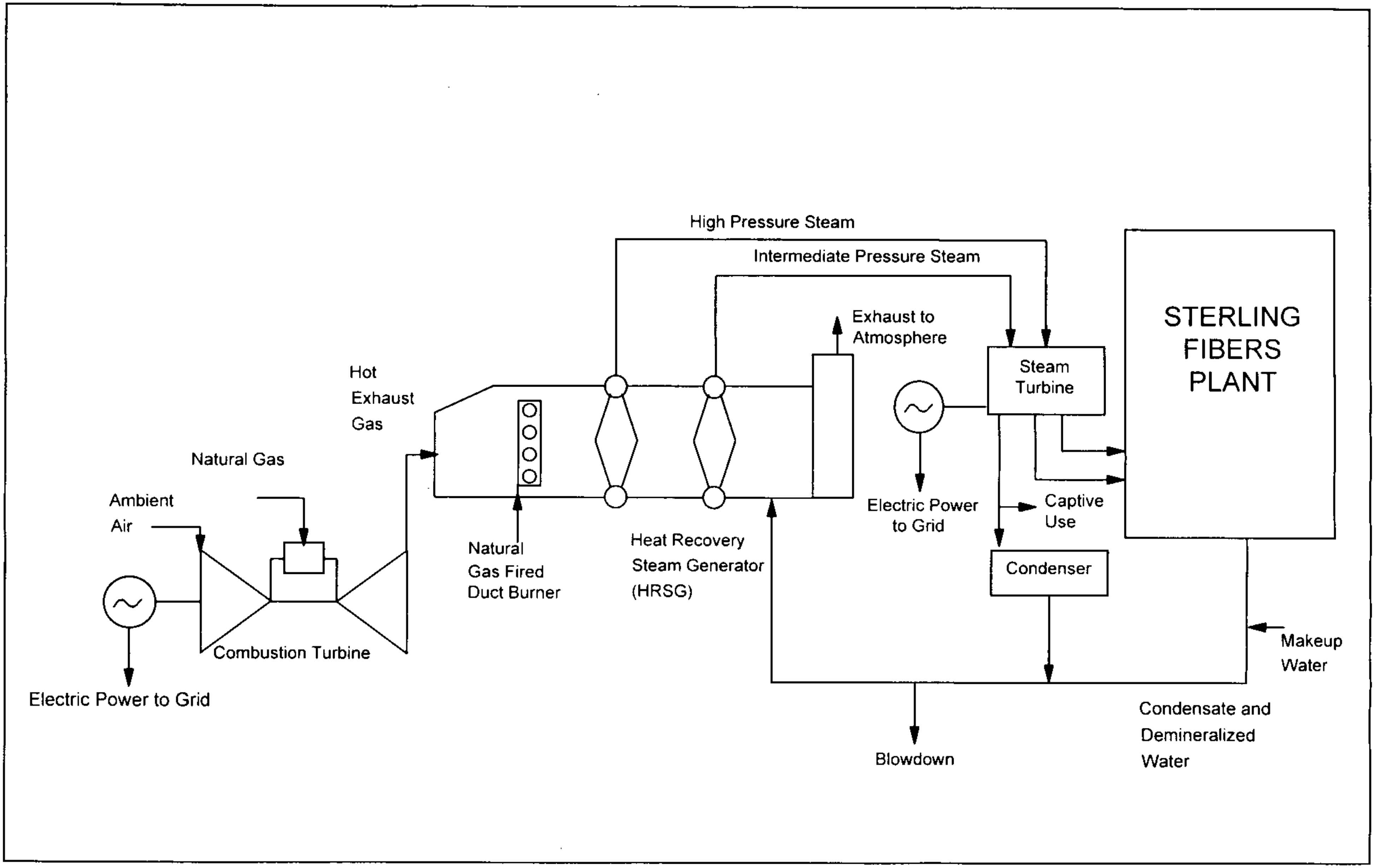


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FIGURE 2-3
SANTA ROSA ENERGY CENTER
SIMPLIFIED PROCESS DIAGRAM

The natural gas fired duct burner will be rated at 585 MMBtu/hr; however, Santa Rosa Energy LLC is requesting a permit limit to restrict the average annual fuel input. The proposed fuel input limit for the duct burner will be 3,280 x 10^6 scf/yr natural gas based on a higher heat value of 1,000 Btu/scf. The duct burner will be manufactured by Coen or equivalent and will be a low NO_x design. The combustion turbine and duct burner will not operate independently.

2.3 OPERATING SCENARIOS

The typical operating scenario for the combustion turbine system will be for the combustion turbine to operate up at or near 100% of the design capacity. Hot combustion turbine exhaust gases will pass through the HRSG exchanging energy to produce steam for Sterling Fibers and the steam turbine. The combustion turbine will fire pipeline grade natural gas.

The duct burner in the HRSG will fire natural gas and will utilize combustion turbine exhaust as the combustion air supply. Consequently, the duct burner cannot operate if the combustion turbine is not operating. The duct burner will fire primarily to accommodate fluctuations in Sterling Fibers steam demand or to meet peek electric demand.

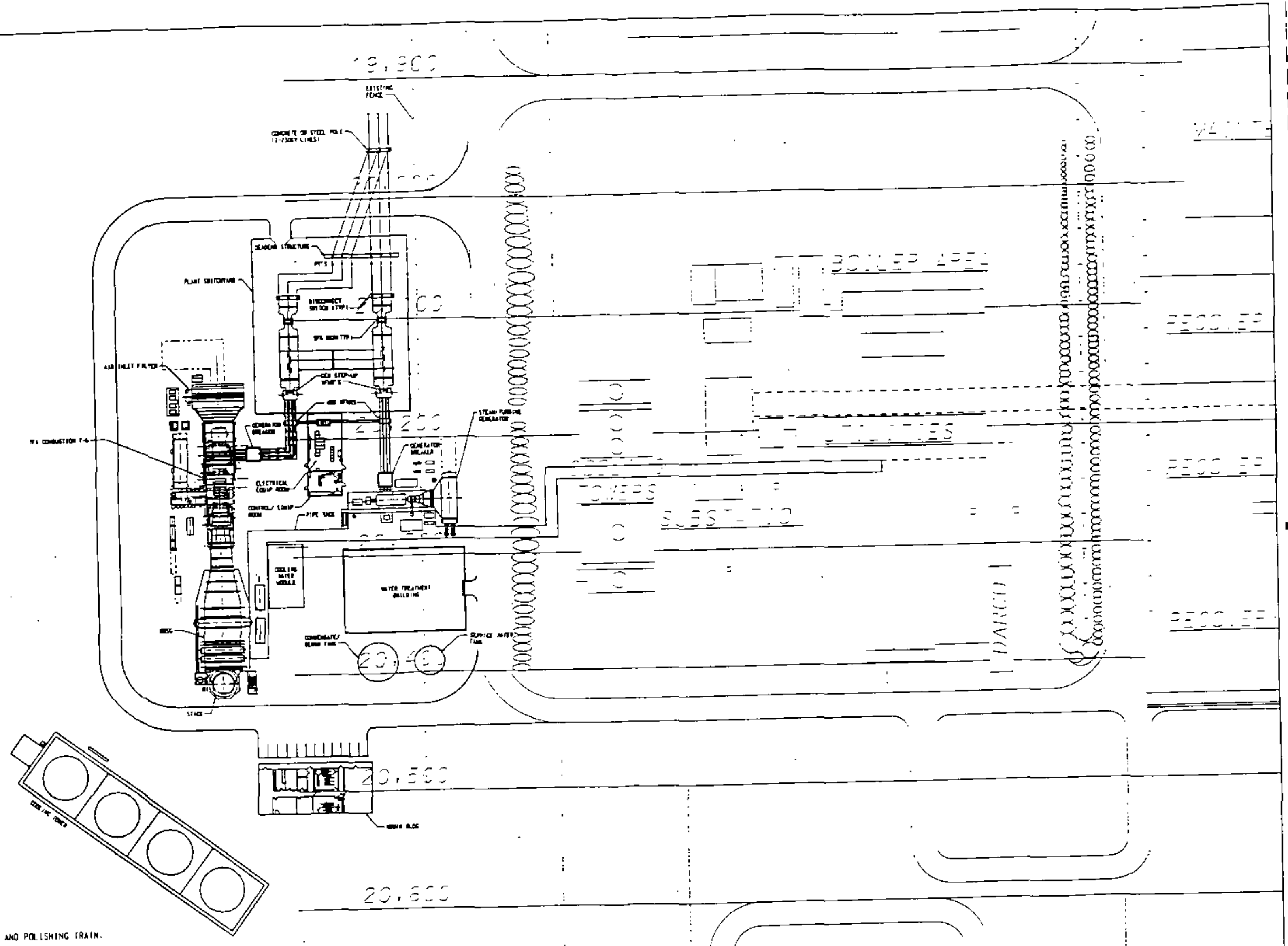
In addition to the operating scenarios described above, there are other operating conditions which may effect the exhaust conditions and/or emission rates from the system. These conditions include power augmentation, start-up and shut-down operations.

Power augmentation is a combustion turbine operating mode where the combustion turbine can be operated beyond normal operating mode design specifications for short periods of time. When additional electric generating capacity is needed on the grid for short periods of time, the electric generating capacity from the combustion turbine can be increased to, for example, approximately 189 MW during winter ambient air conditions.

Start-up operations for the turbine will take up to 240 minutes from initial fuel firing until the system reaches steady-state operation. The proposed emission limits for the turbine cannot be achieved until the unit reaches steady-state conditions.

Turbine shut-down will take up to 180 minutes from lowering the system output below steady-state operation until stopping fuel firing. Again, during shut-down, the combustion turbine and duct burner will be operating below steady-state conditions, so the optimum NO_x emissions control will not be achieved.

Santa Rosa Energy LLC is requesting authorization in accordance with Florida Rule 62-210.700 to allow the startup and shutdown periods, where excess emissions may occur, to go beyond the Florida regulatory limit of two hours in a twenty-four hour period. The manufacturer of the combustion turbine equipment cannot guarantee emission limitations during the time periods of startup and shutdown. The extended times for startups and shutdowns is required due to the size and complexity of the equipment in order to prevent damage to the equipment.



NOTES

1. USE EXISTING RO AND POLISHING TRAIN.

SCALE: 1" = 30'-0"

POLSKY ENERGY CORPORATION

SANTA ROSA ENERGY CENTER

STERLING FIBERS, INC.

BIBB and Associates Inc.

GENERAL ARRANGEMENT
GE 7FA COMBINED CYCLE

3. EMISSIONS INVENTORY

3.1 PROPOSED PROJECT EMISSION RATES

Emission units associated with the proposed project include the combustion turbine and duct burner. The following subsections provide a brief summary of the pertinent emission data for each emission unit.

3.1.1 Combustion Turbine

The proposed combustion turbine will be a General Electric Frame 7F (or equivalent) fueled by natural gas. The turbine will have a nominally rated heat input of 1,596 MMBtu/hr lower heat value (LHV) at an ambient air temperature of 68°F and 60% relative humidity while operating at 100% load. The heat input capacity of the turbine will increase at lower ambient temperatures and decrease at higher ambient temperatures.

The turbine will be equipped with a Dry Low NO_x Combustor for the control of NO_x emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. During the power augmentation operating mode the NO_x concentration may increase up to 12 ppmvd at 15% O_2. Santa Rosa Energy LLC does not plan to operate the proposed combustion turbine in the power augmentation mode for extended periods of time, as recommended by the manufacturer. Typically, the proposed combustion turbine will be operated at or near full normal operating mode load.

The maximum hourly emission rates from the proposed combustion turbine are based on emission factors from performance data sheets supplied by the combustion turbine manufacturer (General Electric). The maximum hourly emission rates and annual emission rates are based on ambient air temperature of 40°F with the turbine operating in the power augmentation load. The 40°F temperature represents the reported annual average of the lowest daily temperature for Pace, FL (44.2 °F) and reflects a worst case condition based on data provided by General Electric for 100%, 75%, 65% and 50% load analyses at 40°F, 68°F, and 92°F ambient air temperatures. The 68°F temperature represents the annual average daily temperature for Pace, FL, and 92°F represents the annual average of the highest daily temperature for Pace, FL (87.5 °F).

A summary of the maximum hourly proposed combustion turbine emission rates is provided in Table 3-1. These emissions do not include startup, shutdown, or malfunction emissions.

3.1.2 Heat Recovery Steam Generator Duct Burner

The Heat Recovery Steam Generator (HRSG) duct burner will have a design heat input capacity of 585 MMBtu/hr higher heat value (HHV). However, Santa Rosa Energy LLC will restrict usage to 3,280 x 10^6 standard cubic feet per year (scf/yr) natural gas based on a higher heat value of 1,000 Btu/scf. The HRSG will primarily operate in the heat recovery or "unfired" mode utilizing heat from the proposed combustion turbine exhaust gases to generate steam. The HRSG and duct burner cannot operate independently from the proposed combustion turbine. The duct burner will be used primarily to meet the steam demand fluctuations of the Sterling Fibers Plant. The duct burner will be of a "low-NO_x" design in order to control emissions of nitrogen oxides. Maximum hourly emission rates from the duct burner are estimated based on operation at full capacity and on emission factors from performance data sheets for the units as supplied by the manufacturer.

A summary of the maximum hourly proposed duct burner emission rates is provided in Table 3-1. These emissions do not include startup, shutdown, or malfunction emissions.

3.1.3 Combined Combustion Turbine and HRSG

Potential annual emissions have been estimated based on the proposed combustion turbine operating in the power augmentation mode at 68°F, 8,760 hours per year and the duct burner operating at full capacity with an annual natural gas fuel restriction of 3,280 x 10^6 scf. A summary of the potential annual emission compared to PSD significance levels is provided in Table 3-2.

TABLE 3-1
SANTA ROSA ENERGY CENTER
MAXIMUM HOURLY EMISSION RATES FROM THE COGENERATION SYSTEM
COMBUSTION TURBINE AND DUCT BURNER FIRING NATURAL GAS ONLY

POLLUTANT	COMBUSTION TURBINE EMISSIONS[a] (lb/hr)	DUCT BURNER EMISSIONS[b] (lb/hr)	TOTAL STACK EMISSIONS[c][d] (lb/hr)
Total Suspended Particulate[e]	9.5	4.7	14.2
Particulate Matter <10 microns[e]	9.5	4.7	14.2
Sulfur Dioxide	1.1	0.6	1.7
Nitrogen Oxides	89.3	46.8	136.1
Volatile Organic Compounds	3.2	11.1	14.3
Carbon Monoxide	52.5	46.8	99.3
Sulfuric Acid Mist[e]	Not Available	Not Available	Not Available
Lead[f]	Not Available	< 0.001	< 0.001
Beryllium[f]	Not Available	<0.00001	<0.00001
Mercury [f]	Not Available	< 0.001	< 0.001
Total Organic and Inorganic HAPs[f]	Not Available	1.10	1.10

(a) Emission rates for each pollutant are the highest short-term rates over the range of ambient air conditions and load levels for the combustion turbine as provided by the combustion turbine vendor. Refer to Table B-1.

(b) Based on full load conditions firing natural gas. Refer to Table B-1.

(c) Combustion turbine with duct burner will be exhausted through a single stack.

(d) Emissions from combustion turbine/duct burner systems operating simultaneously.

(e) Sulfuric acid mist emissions are not included with particulate matter emissions. There are not separate factors available for combustion turbines or duct burners firing natural gas.

(f) AP-42 emissions factors for HAPs are not available for natural gas firing for the combustion turbine thus HAPs were assumed to be insignificant. Natural gas emission factors for natural gas combustion in boilers were used for the duct burner because of the similarity (US EPA AP-42 5th ed, Supplement D, Section 1.4). Total HAPs includes the organic and inorganic species.

TABLE 3-2
SANTA ROSA ENERGY CENTER
MAXIMUM POTENTIAL ANNUAL EMISSIONS

POLLUTANT	COMBUSTION TURBINE WITH DUCT BURNER EMISSIONS[a][b] (ton/yr)	PSD SIGNIFICANCE LEVEL[c] (ton/yr)
Total Suspended Particulate	54.7	25
Particulate Matter <10 microns	54.7	15
Sulfur Dioxide	6.5	40
Nitrogen Oxides	508.3	40
VOC	45.2	40
Carbon Monoxide	347.6	100
Sulfuric Acid Mist	Not Available	7
Lead [b]	0.0008	0.6
Beryllium [b]	0.00002	0.0004
Mercury [b]	0.0004	0.1
Total Organic and Inorganic HAPs [b]	3.10	-

[a] Based on hourly emissions for combustion turbine firing natural gas, i.e., at power augmentation load and an average annual ambient temperature of 68°F; duct burner at reduced annual average capacity firing natural gas; i.e., at 64% load; and both operating at 8,760 hours per year. This scenario represents realistic operating conditions and provides operational flexibility.

[b] HAP emissions are presented for the duct burner only.

[c] From EPA PSD regulations, 40 CFR 52.21(b)(23)(j).

These emissions do not include startup, shutdown, or malfunction emissions as these cannot be calculated or anticipated. The proposed cogeneration facility is subject to PSD review for PM, PM_{10}, VOC, CO, and NO_X based on the potential emissions.

3.2 HAZARDOUS AIR POLLUTANT EMISSIONS

HAP emissions factors are available only for combustion turbines firing oil and not natural gas. Data for HAP emissions is available for natural gas combustion in boilers which is similar to the duct burner operation. HAP emissions were calculated for the duct burner and annual emission rates were determined to be below significant PSD emissions threshold values. HAP emission rates were also below major source applicability thresholds for federal National Emission Standards for Hazardous Air Pollutants (NESHAP).

4. REGULATORY ASSESSMENT

The following subsections contain an assessment of federal and State of Florida air regulations that may potentially be applicable to the proposed project.

4.1 FEDERAL STANDARDS

The following federal regulations potentially apply to the proposed project:

- New Source Performance Standards (NSPS)
- Prevention of Significant Deterioration (PSD) Regulations
- Acid Rain Provisions (Title IV)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)

Specific federal requirements are summarized in Table 4-1 and Table 4-2. A discussion of each is provided in the following subsections.

4.1.1 New Source Performance Standards (NSPS)

The United States Environmental Protection Agency (USEPA) has promulgated standards of performance for specific sources of air pollution at 40 CFR Part 60. These standards are contained in Subparts C through WWW of Part 60. The following Subparts were evaluated to determine applicability to the proposed project.

4.1.1.1 Subpart A - General Provisions

The provisions of 40 CFR 60 Subpart A apply to the owner or operator of any stationary source which contains an affected facility. The provisions of this subpart which are applicable to the Santa Rosa Energy Center are summarized in Table 4-1.

TABLE 4-1
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
SUMMARY OF NSPS GENERAL PROVISIONS WHICH ARE POTENTIALLY APPLICABLE
TO THE PROPOSED COMBUSTION TURBINE AND HEAT RECOVERY STEAM GENERATOR (HRSG)

REGULATORY CITATION	REGULATORY STANDARD	NOTES
40 CFR 60 §60 7(a)	Notification and recordkeeping	The owner or operator shall furnish the Administrator written notification as follows: (1) A notification of the date construction of the facility is commenced postmarked no later than 30 days after such date. (2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date. Startup is defined as "the setting in operation of an affected facility for any purpose." (3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date. (5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with §60.13(c). Notification shall be postmarked no less than 30 days prior to such date. (6) A notification of the anticipated date for conducting the opacity observations required by §60.11(e)(1). The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.
40 CFR 60 §60.7(b)	Notification and recordkeeping	The owner or operator shall maintain records of the occurence and duration of any startup, shutdown, or malfunction in the operation of an affected facilty; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
40 CFR 60 §60.7(c)	Notification and recordkeeping	Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report and/or a summary report form to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with §60.13(h), conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the period. (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the facility. The nature and cause of any malfunction (if known) the corrective action taken or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

TABLE 4-1
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
SUMMARY OF NSPS GENERAL PROVISIONS WHICH ARE POTENTIALLY APPLICABLE
TO THE PROPOSED COMBUSTION TURBINE AND HEAT RECOVERY STEAM GENERATOR (HRSG)

REGULATORY CITATION	REGULATORY STANDARD	NOTES
40 CFR 60 §60.7(d)	Notification and recordkeeping	The summary report form shall contain the information and be in the format shown in 40 CFR §60.7(d) unless otherwise specified by the Administrator. One form shall be submitted for each pollutant monitored.
40 CFR 60 §60 7(f)	Notification and recordkeeping	A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring sytem or monitoring device calibration checks; adjustments and maintenance performed on these sytems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records.
40 CFR 60 §60 7(g)	Notification and recordkeeping	If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.
40 CFR 60 §60.8(a)	Performance tests	Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under Section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results.
40 CFR 60 §60.8(b)	Performance tests	Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless otherwise approved by the Administrator
40 CFR 60 §60.8(c)	Performance tests	Performance tests shall be conducted under such conditions as the Administrator shall specify based on representative performance of the facility. Operations during periods of startup, shutdown, and malfunction do not constitute representative emissions nor shall emissions in excess during periods of startup, shutdown, and malfunction be considered a violation unless otherwise specified in the applicable standard.
40 CFR 60 §60.8(d)	Performance tests	30 days prior notice of any performance test shall be provided to the Administrator, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present.
40 CFR 60 §60.8(e)	Performance tests	Performance testing facilities shall be provided as follows: (1) Sampling ports adequate for test methods applicable to the facility. (2) Safe sampling platforms. (3) Safe access to sampling platforms. (4) Utilities for sampling and testing equipment.
40 CFR 60 §60.8(f)	Performance tests	Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method.
40 CFR 60 §60.13	Monitoring requirements	Establishes minimum criteria for design, installation, and operation of CEMs required under applicable subparts

TABLE 4-2
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
SUMMARY OF NSPS SOURCE SPECIFIC PROVISIONS WHICH ARE POTENTIALLY APPLICABLE
TO THE PROPOSED COMBUSTION TURBINE AND HEAT RECOVERY STEAM GENERATOR (HRSG)

EMISSIONS UNIT	REGULATORY CITATION	REGULATORY STANDARD	NOTES
Combustion Turbine	40 CFR 60 Subpart Da	General Applicability	Standards are only potentially applicable to the HRSG as per §60.40a (b). **NOT APPLICABLE TO THE COMBUSTION TURBINE.**
HRSG Duct Burner	40 CFR 60 Subpart Da	General Applicability	Applies to electric utility combined cycle gas turbines that are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel in the steam generator. Only emissions from the combustion of fuel in the steam generator are subject. An electric utility combined cycle gas turbine is a combined cycle gas turbine used for electrical generation that is constructed for the purpose of supplying more than 1/3 of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system. Potential electrical output capacity is defined as 33 percent of the maximum design heat input capacity of the steam generation unit. The Santa Rosa Energy Center steam generator heat input from the duct burner is 585 MMBtu/hr; potential electrical heat input capacity from the duct burner is 193 MMBtu/hr or 57 MW. The Santa Rosa Energy Center steam electric turbine is sized to generate and sell to the electric grid <75 MW **NSPS IS APPLICABLE TO HRSG.**
	40 CFR 60.42a (a)	Particulate matter emissions cannot exceed 0.03 lb/MMBtu.	
	40 CFR 60.42a (b)	Opacity cannot exceed 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent.	
	40 CFR 60.43a (b)(2)	SO_2 emissions cannot exceed 0.20 lb/MMBtu	
	40 CFR 60.44a	NO_x emissions cannot exceed 0.20 lb/MMBtu for gaseous fuels.	
	40 CFR 60.46a	Compliance is required for the particulate matter, SO_2 and NO_x standards except during start-up, shutdown, or malfunction	
	40 CFR 60.47a	CMS are required.	
HRSG Duct Burner	40 CFR 60 Subpart Db	General Applicability	In accordance with 60.40b (c), if 40 CFR 60 Subpart Da applies, then 40 CFR Subpart Db is not applicable.

TABLE 4-2
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
SUMMARY OF NSPS SOURCE SPECIFIC PROVISIONS WHICH ARE POTENTIALLY APPLICABLE
TO THE PROPOSED COMBUSTION TURBINE AND HEAT RECOVERY STEAM GENERATOR (HRSG)

EMISSIONS UNIT	REGULATORY CITATION	REGULATORY STANDARD	NOTES
Combustion Turbine	40 CFR 60 Subpart GG	General Applicability - The provisions of this subpart apply to all stationary gas turbines with a heat input rating of 10.7 gigajoules per hour (LHV) (10 million BTU per hour) and which commenced construction after October 3, 1977.	Combustion Turbine is subject to this standard based on the applicability definitions. **SANTA ROSA ENERGY CENTER WILL BE IN COMPLIANCE.**
	40 CFR 60 §60.332(a)(1)	**Natural Gas Firing:** NO_X emissions (percent by volume on a dry basis at 15% O_2) shall not exceed 0.0075*(14.4/Rated Capacity in kJ/Watt-Hr)+ F, where rated capacity is 13.48kJ/Watt -Hr for 1,101.9 MMBtu/hr heat input and 77.6 MWe. F is 0. This correlates to an emission limit of 0.0080% NO_X @15% O_2, dry basis or 80 ppmvd @ 15% O_2, for the 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	F is based on the weight % Nitrogen in Natural Gas. Assume F=0 for Santa Rosa Energy Center based on negligible Nitrogen content in natural gas analysis. **SANTA ROSA ENERGY CENTER WILL BE IN COMPLIANCE.**
	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. **NOT APPLICABLE TO THE COMBUSTION TURBINE**
	40 CFR 60 §60.333(a)	SO_2 emissions shall never exceed 150 ppmv @ 15% O_2 dry basis.	**SANTA ROSA ENERGY CENTER WILL BE IN COMPLIANCE.**
	40 CFR 60 §60.333(b)	Fuel shall not be burned which is in excess of 0.8 % by weight sulfur.	Natural gas sulfur content is negligible and less than 0.8% by wt
	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 system 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. **NOT APPLICABLE TO THE COMBUSTION TURBINE**

TABLE 4-2
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
SUMMARY OF NSPS SOURCE SPECIFIC PROVISIONS WHICH ARE POTENTIALLY APPLICABLE TO THE PROPOSED COMBUSTION TURBINE AND HEAT RECOVERY STEAM GENERATOR (HRSG)

EMISSIONS UNIT	REGULATORY CITATION	REGULATORY STANDARD	NOTES
Combustion Turbine	40 CFR 60 §60.334(c)	Monitoring of Operations - For the purpose of reports required under §60.7(c) (see Table 4-2, "General Provisions"), periods of excess emissions that shall be reported are defined as follows: (1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance by the performance test required by §60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed during performance testing. (2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired exceeds 0.8 percent. (3) Ice fog. Each period during which an exemption provided in §60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the dated antime the air pollution control system was reactivated shall be reported.	(1) applies to NO_x emissions monitoring, (2) applies to monitoring of fuel sulfur content, and (3) is not applicable. **SANTA ROSA ENERGY CENTER WILL COMPLY WITH (2) OF THIS SECTION; SECTIONS (1) AND (3) ARE NOT APPLICABLE SINCE THERE IS NOT WATER INJECTION AND §60.332(g) DOES NO T APPLY, RESPECTIVELY.**
	40 CFR 60 §60.335	Test methods defined in this section must be used for all performance tests required.	Alternate methods defined in 40 CFR 60 §60.335(f) may be used to determine compliance.

4.1.1.2 Subpart Da - Electric Utility Steam Generating Units

Subpart Da regulations apply to electric utility steam generating units for which construction is commenced after September 18, 1978 and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 250 million Btu/hour. The proposed combustion turbine emissions are specifically exempt from Subpart Da as combustion turbine emissions are regulated by NSPS Subpart GG (Section 4.1.1.3). Only emissions from the duct burner associated with the HRSG are affected by Subpart Da.

For the natural gas fired duct burner emissions, pollutant emissions standards apply only for PM, SO_2, and NO_x emissions which are limited to 0.03, 0.2 and 0.2 lb/MMBtu, respectively

An initial performance test to demonstrate compliance with the PM and NO_x standard will be required for submittal to FDEP using the test method specified in the regulation. Recordkeeping requirements include, predicted NO_x emissions on a rolling 30 day average, NO_x emissions based on fuel use records, and excess emissions. Continuous Monitoring Systems (CMS) are required for NO_x and either O_2 or CO_2.

The provisions of this Subpart Da which are applicable to the Santa Rosa Energy Center are summarized in Table 4-2.

4.1.1.3 Subpart GG - Stationary Combustion Turbines

The proposed combustion turbine will be subject to Subpart GG for Stationary Combustion Turbines promulgated as 40 CFR 60.330. These provisions apply to stationary combustion turbines with a heat input equal to or greater than 10.7 gigajoules per hour (10.14 MMBtu/hr).

The Subpart specifies a NO_x emission standard based both on the percentage of nitrogen in the fuel combusted and thermal NO_x formation. Assuming conservatively that the nitrogen content in the natural gas is zero, this corresponds to an estimated emission limit of approximately 80 ppmv at 15 percent O_2, dry basis. As specified in Sections 2 and 3, the proposed combustion turbine is equipped with Dry Low NO_x Combustors that will have NO_x emissions of 9 ppmvd for natural gas firing under normal operating conditions. The Subpart also specifies that either an SO_2 standard of 150 ppmv at 15 percent O_2, dry basis, or the fuel combusted may not exceed 0.8 percent sulfur by weight. The combustion turbine will fire only pipeline quality natural gas which contains only trace quantities of sulfur (less than 0.8 percent by weight) primarily as a mercaptan for detection.

Pursuant to the Subpart, an initial compliance test using specified EPA test methods will be required to demonstrate compliance with the aforementioned emission limits. The performance test must be conducted over a range of turbine loads if water/steam injection is being used to control emissions, and the water-to-fuel ratio necessary to comply with the allowable NO_x concentration must be determined at each load point. Testing at 30, 50, 75, and 100 percent of peak load is required. Santa Rosa Energy LLC is proposing Dry Low NO_x technology to control emissions of NO_x, not steam/water injection, and believes the multi-load testing requirement is not applicable to the proposed combustion turbine. Santa Rosa Energy Center will use water/steam injection during the power augmentation to increase mass flow within the turbine. Santa Rosa Energy LLC is not assuming additional emission reduction during power augmentation by the water/steam injection.

Monitoring of the sulfur and nitrogen content of the natural gas combusted is required on a daily basis. Because there will be a NO_x CMS, Santa Rosa Energy LLC will be requesting that EPA grant relief from the daily fuel analysis requirement for nitrogen content.

Santa Rosa Energy LLC is also proposing an alternative to daily sampling of sulfur content of the natural gas fired in the combustion turbine. Upon initial start of operation, fuel sulfur content sampling will be prepared to be conducted twice monthly for six months. If the monitoring shows little variability, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur content sampling will be conducted once per quarter for six quarters. If the monitoring continues to show little variability with continued compliance, then sampling will be proposed semiannually. The sampling and analysis may be conducted by either Santa Rosa Energy Center on the natural gas or the utility.

The provisions of this Subpart which are applicable to the Santa Rosa Energy Center are summarized in Table 4-2.

4.1.2 Prevention of Significant Deterioration (PSD) Regulations

"Major stationary sources" and "major modifications" located in areas designated as attainment or unclassifiable for the NAAQS are subject to PSD regulations. Santa Rosa County, Florida is designated as unclassifiable or in attainment for all criteria pollutants.

Based on the emissions inventory (refer to Section 3), the Santa Rosa Energy Center qualifies as a major stationary source since it is one of the 28 major source categories listed in the regulations, and emits more than 100 tons per year of a criteria pollutant. Therefore, all pollutants for which proposed potential emissions will exceed PSD significance levels are subject to PSD review. For the Santa Rosa Energy Center, these pollutants are PM, PM_{10}, CO, VOC, and NO_X.

As part of PSD review, emission sources of each pollutant, for which a significant net emission increase is proposed, are subject to determination of Best Available Control Technology (BACT). In addition, air quality impact analyses are required for pollutants for which a significant air quality impact is predicted. The significant ambient air quality impact concentrations for Class II Areas are presented in Table 4-3. The air quality impact analysis must include:

- PSD Increment Consumption Analysis, including other increment consuming sources in the area.
- National Ambient Air Quality Standards (NAAQS) impact analysis.

Table 4-3

Significant Ambient Impact Levels

Pollutant	Averaging Period	Significant Impact Levels ($\mu g/m^3$)
Nitrogen Dioxide (NO_2)	Annual	1.0
Sulfur Dioxide (SO_2)	Annual	1.0
	3-Hour	25.0
	24-Hour	5.0
Particulate Matter (PM_{10})	Annual	1.0
	24-Hour	5.0
Carbon Monoxide (CO)	1-Hour	2,000
	8-Hour	500

- Impacts on Class I areas analysis.
- Air Quality Related Values (AQRV) analysis.

BACT Analysis

A BACT analysis is required for PM, PM_{10}, CO, VOC, and NO_X emissions associated with the new proposed combustion turbine/HRSG. A control technology must be selected that will result in the maximum reduction in pollutant emissions considered achievable using current technology while considering energy requirements, environmental impacts, and economic impacts. The methodology used in this study to determine BACT follows the "Top Down" approach previously recommended by the EPA. However, it should be noted that pursuant to a settlement of litigation between EPA and industry trade groups, the "Top Down" requirements are not legally enforceable until established by a formal rulemaking procedure (56 F.R. 34202).

The "Top Down" methodology requires the applicant to first evaluate the control technology which results in the maximum level of emission reduction for a similar source which is currently available. If it is demonstrated that this level of control is not technically or economically feasible for the source under evaluation, then the next most stringent level of control is evaluated. The process continues until an acceptable level is identified. The BACT analysis for this proposed project is provided in Section 5.

PSD Increment Consumption

Federal PSD increments for Class II Areas are established only for PM_{10}, SO_2, and NO_X as shown in Table 4-4. An ambient air quality analysis would be required to demonstrate that the PSD increments for PM_{10} and NO_X would not be exceeded by the proposed project; however, based on the results of the air quality analysis from Section 6, the predicted ambient air quality impacts for PM_{10} and NO_X are not significant. Therefore, based on EPA guidance in the "New Source Review Workshop Manual", a PSD increment consumption analysis is not required.

Table 4-4

Allowable PSD Increments

	Class I ($\mu g/m^3$)	Class II ($\mu g/m^3$)
Sulfur Dioxide		
Annual [a]	2	20
24-hour [b]	5	91
3-hour [c]	25	512
Particulate Matter with Aerodynamic Diameter of 10 Micrometers Or Less (PM_{10})		
Annual [b]	4	17
24-hour [c]	8	30
Nitrogen Dioxide		
Annual [b]	2.5	25

[a] From EPA PSD Regulations

[b] Never to be exceeded.

[c] Not to be exceeded more than once per year.

National Ambient Air Quality Standards

National ambient air quality standards (NAAQS) are established for all six criteria pollutants [SO_2, PM_{10}, CO, ozone (VOC and NO_X are precursors), NO_2, and Lead (Pb)] as shown in Table 4-5. An ambient air quality analysis would be required to demonstrate that NAAQS for PM_{10}, CO, and NO_2 would not be exceeded by the proposed project; however, based on the results of the air quality analysis from Section 6, the predicted ambient air quality impacts for PM_{10}, CO, and NO_2 are not significant. Therefore, based on EPA guidance in the "New Source Review Workshop Manual", no further NAAQS analysis is required.

Impacts on Class I Areas

Any PSD project located near a Class I area must also comply with the significant levels for air quality impacts at the discretion of the Federal Land Manager. Since the proposed facility is not within 100 kilometers of a Class I area, and significant impact is not anticipated at a Class I area, the proposed project is not subject to this provision of the PSD review process.

Additional PSD Impacts Analysis

Sources subject to PSD must also provide an analysis of adverse impacts that might occur due to the project on:

- Visibility
- Soils
- Vegetation
- Growth

The additional impact analysis is addressed in Section 6.

Table 4-5

Federal National Primary And Secondary Ambient Air Quality Standards

Pollutant	Type Of Standard	Averaging Time	Compliance Frequency Parameter	Concentration	
				$\mu g/m^3$	ppm
Sulfur Oxides (as sulfur dioxide)	Primary	24 hour 1 hour	Annual Maximum Arithmetic Mean	365 (260[a]) 80 (60[a])	0.14 (0.1[a]) 0.03 (0.02[a])
	Secondary	3 hour	Annual Maximum	1,300	0.5
PM_{10}	Primary and Secondary	24 hour 24 hour	Annual Maximum Annual Arithmetic Average	150 50	--- ---
Carbon Monoxide	Primary and Secondary	1 hour 8 hour	Annual Maximum Annual Maximum	40,000 10,000	35 9
Ozone	Primary and Secondary	1 hour	Annual Maximum	235	0.12
Nitrogen Dioxide	Primary and Secondary	1 year	Arithmetic Mean	100	0.053
Lead	Primary and Secondary	3 months	Arithmetic Mean	1.5	---

[a] Florida Ambient Air Quality Standards for sulfur dioxide.

4.1.3 Acid Rain Provisions

The cogeneration facility is subject to the Acid Rain Program regulations found in 40 CFR 72 because the facility is a combined cycle cogeneration facility constructed after 15 November 1990 and greater than one-third of its potential electrical output capacity and greater than 219,000 MW-hrs of electricity will be sold to a utility.

The Acid Rain Program permit application for the Santa Rosa Energy Center will be submitted to the permitting authority, which will be EPA Region IV. The application will include identification of the affected unit, a compliance plan citing the regulations, commence operation date, and monitoring, recordkeeping, and reporting requirements.

4.1.4 National Emission Standards for Hazardous Air Pollutants (NESHAP)

NESHAPs promulgated prior to the 1990 Clean Air Amendments (CAAA), found in 40 CFR 61, apply to specific compounds emitted from specific processes. Pursuant to the CAAA, NESHAPs specific to processes identified as emitters of hazardous air pollutants have been promulgated in 40 CFR 63. There are currently not pollutant specific or process specific NESHAPs promulgated or proposed to date which would apply to this project. NESHAPs are scheduled for promulgation in November, 2000 for boilers and stationary turbines which may be applicable after that time.

4.2 STATE OF FLORIDA STANDARDS

Florida air quality regulations are codified as Chapters 62-204 through 62-297 of the Florida Administrative Code (F.A.C.). F.A.C. rules that are potentially applicable to the proposed project are as follows:

- Rule 62-296.320 - General Pollutant Emission Limiting Standards
- Rule 62-296.405 - Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input
- Rule 62-204.240 - Ambient Air Quality Standards

- Rule 62-210.300 - General Construction Permitting Regulations
- Rule 62-210.400 - Prevention of Significant Deterioration (PSD)
- Rule 62-210.550 - Stack Height Policy
- Rule 62-210.700 - Excess Emissions
- Rule 62-210.370 - Reports
- Rule 62-213.400 - Major Source Operating Permits

Table 4-6 summarizes the applicable F.A.C. regulations.

4.2.1 General Pollutant Emission Limiting Standards

Chapter 62-296, Rule 62-296.320 (4)(b) limits visible emissions from any activity not addressed by another Florida Regulation in Chapter 62-296. The proposed combustion turbine will be required to be in compliance with the general visible emissions standard, i.e., visible emissions shall not exceed an opacity of 20%. Visible emission testing must be in accordance with US EPA Method 9. Santa Rosa Energy LLC will comply with the provisions of this regulation.

Chapter 62-296, Rule 62-296.320(4)(c) limits unconfined emissions of particulate matter from activities including vehicular movement, transportation of materials, construction, alteration, demolition or wrecking or industrial related activities. Unconfined emissions of particulate matter may potentially occur during construction of the proposed cogeneration facility. Santa Rosa Energy LLC will take reasonable precautions to prevent such emissions. Wet suppression or similar techniques will be used to control emissions as necessary during construction activities.

TABLE 4-6
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
ANALYSIS OF POTENTIAL FLORIDA STATE APPLICABLE REQUIREMENTS

EMISSIONS UNIT	REGULATORY CITATION	CITATION DESCRIPTION	REGULATORY STANDARD	NOTES
Combustion Turbine	Chapter 62-296, Rule 62-296.320 (4)(b)	Control of Particulate Emissions - Visible Emissions	Opacity shall not exceed 20% (verified by US EPA Method 9).	
Duct Burner	Chapter 62-296, Rule 62-296.405 (1)(a)	Control of Particulate Emissions - Visible Emissions from Fossil Fuel Steam Generators	Opacity shall not exceed 20% (except for one 6 minute period per hour where opacity must not exceed 27% or one 2 minute period where opacity must not exceed 40%). Annual testing is required.	Annual testing for opacity is required for the duct burner.
Duct Burner	Chapter 62-296, Rule 62-296.405 (1)(b)	Control of Particulate Emissions - Fossil Fuel Steam Generators	Particulate matter emissions shall not exceed 0.1 lb/MMBtu based on, as measured by applicable test methods.	
Duct Burner	Chapter 62-296, Rule 62-296.405 (1)(c)	Control of Sulfur Compound Emissions - Fossil Fuel Steam Generators	Not applicable to the proposed Santa Rosa Energy Center because it will fire natural gas only. The rule applies to liquid and solid fuel firing.	Not applicable to the Santa Rosa Energy Center
Duct Burner	Chapter 62-296, Rule 62-296.405 (1)(d)	Nitrogen Oxides Emissions - Fossil Fuel Steam Generators	Not applicable to the proposed Santa Rosa Energy Center because it is not located in Duval, Manatee, Leon, or Hillsborough Counties.	Not applicable to the Santa Rosa Energy Center
Combustion Turbine and Duct Burner	Chapter 62-204, Rule 62-204.240 (1)(d)	Ambient Air Quality Standards	This rule defines the allowable in ambient air concentrations for SO_2, CO, PM_{10}, Ozone, NO_2, and lead.	Florida SO_2 standards are more stringent than the National Ambient Air Quality Standard.
General	Chapter 62-210, Rule 62-210.300 (1)	Air Permits	Requires the owner of any new emission unit to obtain an air construction permit prior to the beginning of construction.	
General	Chapter 62-210, Rule 62-210.300 (2)	Major Source Operating Permits	General provisions; applicability; permit application requirements; permit content; federally enforceable requirements; compliance requirements, etc.	
General	Chapter 62-210, Rule 62-210.370	Reports	Annual reports are required.	

TABLE 4-6
SANTA ROSA ENERGY CENTER, PACE, FLORIDA
ANALYSIS OF POTENTIAL FLORIDA STATE APPLICABLE REQUIREMENTS

EMISSIONS UNIT	REGULATORY CITATION	CITATION DESCRIPTION	REGULATORY STANDARD	NOTES
General	Chapter 62-210, Rule 62-210.550 (1)-(3)	Stack Height Policy	Specifies the stack height requirements and dispersion techniques allowable in the permitting of air emission sources.	
General	Chapter 62-210, Rule 62-210.710	Excess Emissions	Provides allowances for excess emissions for emissions units that may occur during startup, shutdown, malfunctions, and load changes.	Santa Rosa Energy LLC is requesting authorization in accordance with Florida Rule 62-210.700 to allow the startup and shutdown periods, where excess emissions may occur, to go beyond the Florida regulatory limit of two hours in a twenty-four hour period.
General	Chapter 62-212, Rule 62-212.400	Prevention of Significant Deterioration (PSD) - Florida construction review requirements for construction in clean air areas.	Project is subject to the federal and Florida PSD regulations for CO, VOC, NO_x and PM/PM_{10} since the project will emit these pollutants in quantities greater than the allowable emissions increase levels. Facility will be required to demonstrate BACT and conduct an Ambient Air Quality Analysis for these pollutants.	

4.2.2 Fossil Fuel Steam Generators

Florida standards for Fossil Fuel Steam Generators are summarized in the following subsections.

4.2.2.1 Visible Emission Regulations

Chapter 62-296, Rule 62-296.405 (1)(a) limits visible emissions from fossil fuel steam generators with a heat input of greater than 250 MMBtu per hour. This rule requires that visible emissions shall not exceed an opacity of 20% except for one six-minute period per hour during which opacity must not exceed 27 percent, or one two-minute period per hour during which opacity must not exceed 40 percent. Annual testing of opacity is required. This restriction will apply to the HRSG only. Santa Rosa Energy LLC will comply with the provisions of this regulation.

4.2.2.2 Particulate Matter Standard

Particulate matter emissions from fossil fuel steam generators are regulated Chapter 62-296, Rule 62-296.405 (1)(b) which limits emissions from any new source with a rated heat input greater than 250 MMBtu/hr to 0.1 lbs particulate per MMBtu heat input. Chapter 62-296, Rule 62-296.405 (1)(b) also states that compliance with this regulation shall be determined by approved test methods and procedures. This restriction will apply to the HRSG only. Santa Rosa Energy LLC will comply with the provisions of this regulation.

4.2.2.3 Sulfur Dioxide Regulation

Chapter 62-296, Rule 62-296.405 (1)(c) limits the sulfur dioxide emissions for fossil fuel steam generators firing liquid and solid fuels, only. The Santa Rosa Energy LLC will fire only natural gas in the duct burner; therefore this regulation does not apply.

4.2.2.4 Nitrogen Oxides Regulation

Chapter 62-296, Rule 62-296.405 (1)(d) limits the nitrogen oxide emissions for fossil fuel steam generators located within specified counties including: Duval, Manatee, Leon, and Hillsborough. The Santa Rosa Energy Center will be located in Santa Rosa County and, therefore, not subject to the nitrogen oxide requirements under this regulation.

4.2.3 Ambient Air Quality Standards

Chapter 62-204, Rule 62-204.240 (1)(d) defines the allowable increases in ambient air concentrations for SO_2, CO, PM_{10}, ozone, NO_2, and lead. Detailed dispersion modeling results indicating compliance for the Santa Rosa Energy Center along with a description of the modeling methods employed are contained in Section 6.

4.2.4 Construction Permitting Regulations

4.2.4.1 General Construction Requirements

Chapter 62-210, Rule 62-210.300 requires that an air construction permit be obtained prior to the beginning of construction. Chapter 62-212, Rule 62-212.300 (3) details the minimum general information which must be included with an application for a construction permit. The following general information must be included with each application:

- The nature and amounts of emissions from the emissions unit (provided in Section 3).
- The location, design, construction, and operation of the emissions unit to the extent necessary to allow the Department to determine whether construction or modification of the emissions unit would result in violations of any applicable provisions of Chapter 403, Florida Statutes, or Department air pollution rules, or whether the construction or modification would interfere with the attainment and maintenance of any state of national ambient air quality standard (provided in Sections 2 - 6).

4.2.4.2 Florida Prevention of Significant Deterioration (PSD)

Chapter 62-212, Rule 62-212.400 (5) specifies the preconstruction and post construction review requirements. The requirements to be considered include:

- A technology review for applicable emissions limitations (e.g., 40 CFR Parts 60).
- Best Available Control Technology (for significant PSD pollutants).
- Ambient Air Impact Analysis (Ambient Air Quality Standard or Maximum Allowable Increase).
- Additional Impact Analysis (Visibility, Soils, and Vegetation as Required).
- Preconstruction Air Quality Monitoring and Analysis.
- Post Construction Monitoring.

Florida PSD regulations in addition to the federal PSD regulations are addressed in this application package.

4.2.5 Stack Height Policy

Chapter 62-210, Rule 62-210.550 (1) - (3) specifies the stack height requirements and dispersion techniques allowable in the permitting of air emission sources. Santa Rosa Energy LLC will comply with the provisions of this regulation as detailed in Section 6.

4.2.6 Excess Emissions

Chapter 62-210, Rule 62-210.700 provides allowances for excess emissions for emissions units that may occur during startup, shutdown, malfunctions, and load changes. Excess emissions periods are expected to occur for startups and shutdowns for the proposed cogeneration plant.

Santa Rosa Energy LLC is requesting authorization in accordance with Florida Rule 62-210 700 to allow the startup and shutdown periods, where excess emissions may occur, to go beyond the

, Florida regulatory limit of two hours in a twenty-four hour period. The manufacturer of the combustion turbine equipment cannot guarantee emission limitations during the time periods of startup and shutdown. The extended times for startups and shutdowns is required due to the size and complexity of the equipment in order to prevent damage to the equipment.

4.2.7 Reports

Chapter 62-210, Rule 62-210.370 establishes the requirements for the annual reporting for major stationary sources of air pollution. Santa Rosa Energy LLC will be required to submit annual reports including emissions information since it is classified as a Title V facility.

4.2.8 Major Source Operating Permits

Major stationary sources are required to submit a Title V application pursuant to the requirements outlined in FDEP Chapter 62-213, Rule 62-213.400. The Title V permitting process requires sources to identify applicable requirements for emission units which are subject to federal and state requirements or those which emit regulated air pollutants in significant quantities. The source is also required to certify current and future compliance with identified applicable requirements and propose methods by which future compliance determinations will be based. A new source applying for a Part 70 permit must be issued the Part 70 permit prior to the start of operation of the new source. However, FDEP allows construction permit extensions until a Title V operating permit can be issued as long as a Title V application is submitted either 60 days prior to the expiration of the construction permit or within 180 days of startup of a new source, which ever is more stringent. Santa Rosa Energy LLC will comply with this requirement by submitting a Title V within the required time limits

5. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 INTRODUCTION

The Clean Air Act, as amended in 1977 and 1990, prescribes several technology-based limitations affecting new or modified sources of air pollutant emissions. One such limitation is that of the New Source Performance Standards (NSPS) set by the United States EPA and adopted by FDEP. NSPS require that specific categories of new or modified stationary sources meet uniform national standards for specific pollutants based on the degree of emission limitation achievable through utilization of the demonstrated technology available at the time of their promulgation.

In addition to the technology-specific requirements as presented in the NSPS, criteria pollutants potentially emitted in significant quantity from any major source are regulated under provisions found in the Prevention of Significant Deterioration (PSD) regulations. The PSD regulations requires that the Best Available Control Technology (BACT) be used to control these pollutant emissions. BACT is defined in 40 CFR 52.21 (b)(12) as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the

application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation, and shall provide for compliance by means which achieve equivalent results.

A BACT determination is a case-by-case analysis that addresses the technological question of whether a proposed control technique can be considered BACT for the particular application or whether a more stringent level of emission control should be used. This determination involves an assessment of the availability of applicable technologies capable of sufficiently reducing a specific pollutant emission, as well as weighing the economic, energy, and environmental impacts of using each technology. The selected BACT must be at least as stringent as NSPS and State Implementation Plan limits for the source.

The methodology used in this study to determine BACT follows the "top-down" approach previously recommended by the EPA. However, it should be noted that pursuant to a settlement of litigation between EPA and industry trade groups, the "top-down" BACT requirements are not legally enforceable until established by a formal rulemaking procedure (56 F.R. 34202 26, July 1991). The "top-down" BACT contains the following elements:

- Determination of the most stringent control alternatives potentially available
- Discussion of the technical and economic feasibility of each alternative.
- Assessment of energy and environmental impacts, including toxic and hazardous pollutant impacts, of feasible alternatives.
- Selection of the most stringent control alternative that is technically and economically feasible and that provides the best overall control of all pollutants.

The BACT analysis for the proposed cogeneration facility considers emission controls for VOC, PM/PM_{10}, CO, and NO_x potentially emitted from the combustion turbine and the duct burner.

This approach to BACT as presented in federal regulations is also the accepted approach in FDEP regulations.

5.2 BACT ANALYSIS FOR THE PROPOSED COMBUSTION TURBINE

BACT analyses for the proposed combustion turbine are required for the following PSD affected pollutants: PM/PM_{10}, VOC, CO, and NO_X. A review of the RACT/BACT/LAER Clearinghouse (RBLC) for natural gas fired turbines was conducted and is included in Table 5-7 through Table 5-10. The following summarizes the types of emission control methods utilized by the combustion turbines listed in the RBLC:

<u>VOC (Table 5-7)</u>

- Oxidation catalyst
- Good combustion practices
- Turbine design

<u>PM/PM_{10} (Table 5-8)</u>

- Combustion of clean fuels (e.g., natural gas)
- Good combustion practices

<u>CO (Table 5-9)</u>

- Oxidation catalyst
- Good combustion practices

<u>NO_X (Table 5-10)</u>

- $SCONO_X$™
- Selective Catalytic Reduction (SCR)
- Dry low NO_x combustors
- Good combustion practices
- Combinations of the above

Santa Rosa Energy LLC has evaluated these and other potentially available add-on controls and operating practices to control emissions in gaseous streams to determine which processes could be considered BACT for the proposed combustion turbine. The applicable technologies are discussed in the following subsections.

5.2.1 BACT for Volatile Organic Compounds

The RBLC search for natural gas fired turbines was performed for VOC entries. A summary of the search has been presented in Table 5-7. The RBLC presented entries with good combustion practices and catalytic oxidation add-on control technology. Santa Rosa Energy LLC has identified thermal oxidization, catalytic oxidation, adsorption, and condensation as the most stringent control alternatives potentially available to control VOC emissions in gaseous streams and have included these technologies in the BACT analysis.

5.2.1.1 Discussion of Technical Feasibility of VOC Control Alternatives

Thermal Oxidation

Thermal oxidation is the process of oxidizing organic compounds to form carbon dioxide and water. Thermal oxidizers rely on high combustion temperatures, residence time, and turbulence to promote oxidation. Since the VOC concentration is very low in the turbine exhaust gases (i.e., between 4 and 10 ppm, typically) and is predominantly uncombusted methane/ethane, (which are not VOC per US EPA and FDEP definitions), from the natural gas combustion in the turbine, additional thermal treatment of the combustion gases for VOC emission control will not be effective. Further, there is no evidence in the literature that thermal oxidation has been applied to control VOC emissions from a combustion turbine. Therefore, thermal oxidation is not considered technically feasible and is not BACT for VOC emissions control from the proposed combustion turbine.

Catalytic Oxidation

Catalytic oxidation allows the oxidation of VOC present in exhaust gases to form CO_2 and water in the presence of a catalyst, typically a precious metal. While catalytic oxidation is a technically feasible control technique for VOC reduction in the combustion turbines exhaust gas streams, it should be noted that catalyst performance is affected by turbine exhaust temperature, oxygen content, VOC content/species and many other factors. Many of these parameters are continuously changing during operation of a combined cycle cogeneration system. In addition, the large amounts of catalyst required will increase back pressure on the combustion turbine, thereby decreasing the efficiency of turbine.

Catalytic oxidization is technically feasible for VOC emissions abatement from the proposed combustion turbine. The benefit of using a catalyst must be balanced with the affect it will have on the overall system performance, and on other emissions. A catalyst could be installed in the combined exhaust of the proposed combustion turbine and heat recovery steam generator duct burner, however, the catalyst effectiveness in reducing VOC emissions would be 0% to 30%, average of 15%, per vendor expected performance.

Further evaluation of catalytic oxidation is provided in Section 5.2.1.2.

Adsorption

Adsorption systems typically use activated carbon or resins to physically remove vapor phase organic compounds from a gas stream. The organic compounds are bound to the carbon by van der Waals forces. Typically, the gas stream passes through a bed of adsorption media at a low face velocity and the organic compounds are adsorbed on the surface of the adsorption media. Carbon adsorption is not effective for low molecular weight compounds such as methane or ethane. Combustion stream temperatures below 100°F and high VOC concentrations are most desirable. VOC concentrations in the turbine exhaust gases are very low, and exit temperatures are well above 100°F, making carbon adsorption impractical. In addition, there is no evidence that adsorption techniques have been applied to remove VOC emissions from proposed combustion turbines. Therefore, application of adsorption technologies to the proposed combustion turbine is not considered to be technically feasible and therefore is not BACT.

Condensation

Condensation is the technique by which the gas stream temperature is lowered or the gas stream is pressurized (or some combination thereof) such that the VOC partial pressure reaches the VOC vapor pressure (i.e., saturation is reached). After saturation is reached, as the gas stream temperature is lowered and/or the gas stream pressure is increased, the VOC is condensed. Condensation is normally used for gas streams that are saturated or nearly saturated with VOC.

In the case of the very low VOC content in the turbine exhaust streams, the energy required to increase pressure and/or decrease temperatures enough to reach saturation makes condensation technically infeasible. Given the large gaseous volume generated from a combustion turbine and the low VOC content of combustion turbine exhaust streams, condensation is not considered to be a technically feasible method to abate VOC emissions. There is no evidence in the literature indicating that condensation has been applied to combustion turbine exhaust streams to remove VOC. Therefore, condensation is not BACT for removal of VOC from the proposed combustion turbine exhaust streams.

Good Combustion Practices

Good combustion practices means operation of the proposed combustion turbine at high combustion efficiency, thereby reducing products of incomplete combustion, e.g., VOC. The proposed combustion turbine will be designed to maximize combustion efficiency. The Dry Low NO_X Combustor technology provided by General Electric achieves 1.4 ppm VOC emissions which is lower than many BACT determinations from the RBLC. The vendor will provide Operation and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency. It is proposed that the use of good combustion practices is BACT for minimizing VOC emissions from the proposed combustion turbine.

5.2.1.2 BACT Selection for VOC

Oxidation catalyst and good combustion practices with Dry Low NO_x Combustors have been identified as technically feasible alternatives for controlling VOC emissions from the combustion turbine proposed for the Santa Rosa Energy Center. Based on the level of reduction of VOC emissions at design capacity for the system, these are ranked as follows:

Combustion firing

Rank	Control Option	Expected VOC Emissions
1	Oxidation Catalyst	1.2 ppm
2	Good Combustion Practices with Dry Low NO_x Combustion	1.4 ppm

The following evaluation considers economic impacts of applying oxidation catalyst to control VOC emissions for the proposed combustion turbine at the Santa Rosa Energy Center

Economic Impacts of Oxidation Catalyst

Annualized costs have been determined for use of an oxidation catalyst system to determine the economic impacts on the proposed Santa Rosa Energy Center. The annualized costs were calculated based on the standardized procedures and algorithms from the Fourth Edition of the OAQPS Control Cost Manual (U.S. EPA, EPA 450/3-90-006). Capital costs associated with the oxidation catalyst system equipment costs were based on a vendor cost estimate. Total annualized capital investment and annualized cost of operating an oxidation catalyst system were calculated using algorithms from the OAQPS Control Cost Manual.

A quote was received from Engelhard for an oxidation catalyst. A summary of the capital costs and annualized costs associated with operating an oxidation catalyst system for a VOC emissions reduction for the combustion turbine/duct burner cogeneration system is presented in Table 5-1 and Table 5-2. The annualized cost estimated in Table 5-2 considers operation of the oxidation catalyst at 8,760 hours per year.

TABLE 5-1
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
VOC CATALYST SYSTEM CAPITAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard VOC Catalyst System[b]	1.00 A	=	$	770,000
Instrumentation	0.10 A	=	$	77,000
Sales taxes	0.03 A	=	$	23,100
Freight	0.05 A	=	$	38,500
Purchased equipment cost, PEC	B = 1.18 A	=	$	908,600
Direct installation costs				
Foundations & supports	0.08 B	=	$	72,688
Handling & erection	0.14 B	=	$	127,204
Electrical	0.04 B	=	$	36,344
Piping	0.02 B	=	$	18,172
Insulation	0.01 B	=	$	9,086
Painting	0.01 B	=	$	9,086
Direct installation costs	0.30 B	=	$	272,580
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	1,181,180
Indirect Costs (installation)				
Engineering	0.10 B	=	$	90,860
Construction and field expenses	0.05 B	=	$	45,430
Contractor fees	0.10 B	=	$	90,860
Start-up	0.02 B	=	$	18,172
Performance test	0.01 B	=	$	9,086
Contingencies	0.03 B	=	$	27,258
Total Indirect Costs, IC	0.31 B	=	$	281,666
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	1,462,846

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 8 December 1997.

TABLE 5-2
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
VOC CATALYST SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS	COST
Direct Annual Cost, DC		
Replacement parts, catalyst (3 year life)		
Catalyst cost[a]	0.381 [b] x $ 840,000 x 1.08	$ 345,690
Spent catalyst removal cost	0.381 [b] x $ 30,000	$ 11,432
Total DC		$ 357,122
Indirect Annual Costs, IC		
Administrative charges	2% of Total Capital Investment = 0.02 ($1462846)	$ 29,257
Property tax	1% of Total Capital Investment = 0.01 ($1462846)	$ 14,628
Insurance	1% of Total Capital Investment = 0.01 ($1462846)	$ 14,628
Capital recovery[c]	0.142 [1462846 - 30000 - 840000(1.08)]	$ 74,840
Total IC		$ 133,354
Performance Penalty [f]	164.9 kW x 8,760 hr/yr x $ 0.04 /kW-hr[e]	$ 57,781
Total Annual Cost		$ 548,257

Uncontrolled VOC Emission Rate[d]	(lb/hr)	capacity factor	(hr/yr)	(ton/yr)
Combustion Turbine (natural gas):	3.2	100%	8,760	14.0
Duct Burner (natural gas):	11.1	64%	8,760	31.1
Total Uncontrolled VOC Emission Rate, ton/yr				45.1
Estimated VOC Control Efficiency[g], %				15%
Controlled VOC Emission Rate, ton/yr				38.4
Estimated tons of VOC Controlled, ton/yr				6.8
Annual Cost per Ton VOC Controlled, $/ton				$ 80,987

[a] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[b] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[c] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142

[d] Annual emissions assuming the combustion turbine operates at power augmentation load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[e] Average energy cost is $0.04/kW-hr.

[f] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 164.9 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[g] 15% VOC average reduction expected for typical load conditions per vendor performance data sheet (0% - 30%).

Based on the vendor supplied cost estimates and the methodology presented in the OAQPS Control Cost Manual, the total capital investment that would be required for an oxidation catalyst system to reduce VOC emissions by 15% for the combustion turbine/duct burner system is $1,462,846. The annualized operating costs for operating an oxidation catalyst system for the proposed Santa Rosa Energy Center are $548,257.

Typically, control costs are also evaluated on the cost effectiveness based on annualized costs in dollars per ton of pollutant removed. Based on the maximum amount of VOC emissions that would be expected to be removed by an oxidation catalyst oxidation catalyst system for the proposed Santa Rosa Energy Center, costs are estimated to be in excess of $80,987 per ton of VOC removed to achieve VOC emissions reduction of 15%. For the combustion turbine contribution, the cost effectiveness is higher. The use of an oxidation catalyst system is not cost effective for the proposed Santa Rosa Energy Center system, both in terms of annualized costs and dollar per ton cost effectiveness. Oxidation catalysts for VOC abatement is not BACT because it is not an economically feasible control method.

5.2.1.3 Conclusion

Based on the above analysis, Santa Rosa Energy LLC proposes that BACT for VOC emissions from the proposed combustion turbine be good combustion practices. The economic evaluation for catalytic oxidation, which is considered to be a technically feasible control technique, indicated that the control method is not cost-effective.

5.2.2 BACT for Particulate Matter

The RBLC search of entries for PM/PM_{10} control determinations for natural gas fired combustion turbines was completed. A summary of the search is presented in Table 5-8. Add-on control technologies for PM/PM_{10} control were not identified as BACT according to the RBLC. Acceptable control techniques included combustion of clean fuels (e.g., firing natural gas).

Santa Rosa Energy LLC has identified baghouses, electrostatic precipitators, scrubbers and combustion of clean fuels as the most stringent control alternatives potentially available to control PM/PM_{10} in gaseous streams and have included these technologies in the BACT analysis.

5.2.2.1 Discussion of the Technical and Economic Feasibility

Add-on Controls

The three add-on control technologies identified for particulate matter removal are a baghouse, electrostatic precipitator, and wet scrubber. A baghouse removes particulate matter by passing the gas stream through a porous filtration medium, (e.g., fabric or fiberglass filter) designed to capture and remove particulate matter from the gas stream as it passes through the filter. An electrostatic precipitator imparts an electric charge to particles via electrical plates in the gas stream. The charge applied is opposite that of the collection plates, thereby allowing migration of the oppositely charged particulate matter to the collection plates for removal from the gaseous stream. A scrubber physically removes particulate matter from a gas stream via impaction of the particulate matter with liquid droplets (usually water). The particulate matter adheres to the droplets which fall from the airstream due to gravitational forces.

There are three reasons why add-on control technologies are not technically feasible for the combustion turbine PM/PM_{10} emissions control:

1. The installation of an add-on control will create an unacceptable back pressure on the turbine. Combustion turbine performance is very sensitive to back pressure because it reduces the expansion pressure ratio and energy efficiency, thereby resulting in reduced power output, increased fuel usage, and increased emission rates (e.g., NO_x, CO).

2. Combustion in a turbine requires a high level of excess air, and thus produces high exhaust gas volumes. These high gas volumes in turn increase the size and cost of add-on controls, making them unreasonable for economic reasons.

3. The increased gas volume results in low pollutant concentrations. The projected PM/PM_{10} concentration without add-on controls is less than 0.02 gr/dscf. Further reduction below these levels would be minimal.

Based on the above, add-on control technologies are not considered technically feasible for controlling PM/PM_{10} emissions from the combustion turbine. There is not evidence that add-on controls have been commercially used for PM/PM_{10} control for combustion turbines, and add-on controls are therefore not considered to be BACT for the proposed combustion turbine system

Combustion of Clean Fuels

The combustion of clean fuels to minimize PM/PM_{10} emissions is accomplished by burning fuels which lack impurities in conjunction with good combustion practices to ensure complete combustion. The cleanest fuel commercially available in large quantities is natural gas. Natural gas is designated as the only fuel for the combustion turbine. Combustion of clean fuels is technically feasible for the proposed combustion turbine for PM/PM_{10} control and is proposed as BACT.

5.2.2.2 Conclusion

Based on the above analysis, it is proposed that BACT for PM/PM_{10} emissions from the combustion turbine be combustion of clean fuels. Since the only technically feasible alternative was determined to be BACT, an economic analyses is not required and is not presented.

5.2.3 BACT for Carbon Monoxide

A search of the US EPA RBLC was conducted for CO control determinations for natural gas fired combustion turbines. A summary of the results is presented as Table 5-9. Catalytic oxidation was the only add-on control technology determined to be technically feasible. Other acceptable control techniques include turbine design, and good combustion practices. No additional CO control techniques were identified by Santa Rosa Energy LLC.

5.2.3.1 Discussion of Technical Feasibility of CO Control Alternatives

Catalytic Oxidation

Catalytic oxidation converts CO to carbon dioxide (CO_2) in the presence of a catalyst (typically a precious metal), usually deposited onto a solid honeycomb substrate. Installation of a catalytic oxidation unit in the heat recovery steam generator downstream of the duct burner is a technically feasible control method.

Good Combustion Practices

Good combustion practices means operation of the combustion turbine at high combustion efficiency, thereby, reducing products of incomplete combustion. The combustion turbine will be designed to maximize combustion efficiency. General Electric's Dry Low NO_x Combustor technology will achieve a CO concentration in the combustion turbine exhaust gases of 9 ppm, for normal operation, at or near 100% load and 15 ppm at the power augmentation mode which is lower than many BACT determinations from the RBLC. The vendor will provide Operation and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency

5.2.3.2 BACT Selection for CO

Oxidation catalyst and good combustion practices with Dry Low NO_x Combustors have been identified as technically feasible alternatives for controlling CO emissions from the combustion turbine proposed for the Santa Rosa Energy Center. Based on the level of reduction of CO emissions at design capacity for the system, these are ranked as follows:

Combustion firing

Rank	Control Option	Expected CO Emissions
1	Oxidation Catalyst	1.4 ppm 2.3 ppm (Power Augmentation)
2	Good Combustion Practices with Dry Low NO_x Combustion	9 ppm 15 ppm (Power Augmentation)

The following evaluation considers economic impacts of applying oxidation catalyst to control CO emissions for the proposed combustion turbine at the Santa Rosa Energy Center.

Economic Impacts of Oxidation Catalyst

Annualized costs have been determined for use of an oxidation catalyst system to determine the economic impacts on the proposed Santa Rosa Energy Center. The annualized costs were calculated based on the standardized procedures and algorithms from the Fourth Edition of the OAQPS Control Cost Manual (U.S. EPA, EPA 450/3-90-006). Capital costs associated with the oxidation catalyst system equipment costs were based on a vendor cost estimate. Total annualized capital investment and annualized cost of operating an oxidation catalyst system were calculated using algorithms from the OAQPS Control Cost Manual.

Cost and performance data for a CO catalyst was obtained from Engelhard. A summary of the capital costs and annualized costs associated with operating an oxidation catalyst system for a CO emissions reduction for the combustion turbine/duct burner cogeneration system is presented in Table 5-3 and Table 5-4. The annualized cost estimated in Table 5-4 is based on operation of the oxidation catalyst while achieving 85% CO emission reduction (per the vendor) and operation of the cogeneration system 8,760 hours per year.

TABLE 5-3
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
CO CATALYST SYSTEM CAPITAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard CO Catalyst System[b]	1.00 A	=	$	770,000
Instrumentation	0.10 A	=	$	77,000
Sales taxes	0.03 A	=	$	23,100
Freight	0.05 A	=	$	38,500
Purchased equipment cost, PEC	B = 1.18 A	=	$	908,600
Direct installation costs				
Foundations & supports	0.08 B	=	$	72,688
Handling & erection	0.14 B	=	$	127,204
Electrical	0.04 B	=	$	36,344
Piping	0.02 B	=	$	18,172
Insulation	0.01 B	=	$	9,086
Painting	0.01 B	=	$	9,086
Direct installation costs	0.30 B	=	$	272,580
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	1,181,180
Indirect Costs (installation)				
Engineering	0.10 B	=	$	90,860
Construction and field expenses	0.05 B	=	$	45,430
Contractor fees	0.10 B	=	$	90,860
Start-up	0.02 B	=	$	18,172
Performance test	0.01 B	=	$	9,086
Contingencies	0.03 B	=	$	27,258
Total Indirect Costs, IC	0.31 B	=	$	281,666
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	1,462,846

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 08 December 1997.

TABLE 5-4
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
CO CATALYST SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS					COST
Direct Annual Cost, DC						
Replacement parts, catalyst (3 year life)						
Catalyst cost[a]	0.381 [b]x $ 840,000	x	1.08		$	345,690
Spent catalyst removal cost	0.381 [b]x $ 30,000				$	11,432
Total DC					$	357,122
Indirect Annual Costs, IC						
Administrative charges	2% of Total Capital Investment = 0.02 ($1462846)				$	29,257
Property tax	1% of Total Capital Investment = 0.01 ($1462846)				$	14,628
Insurance	1% of Total Capital Investment = 0.01 ($1462846)				$	14,628
Capital recovery[c]	0.142 [1462846 - 30000 - 840000(1.08)]				$	74,840
Total IC					$	133,354
Performance Penalty [f]	164.9 kW	x	8,760 hr/yr	x $ 0.04 /kW-hr[e]	$	57,781
Total Annual Cost					$	548,257

Uncontrolled CO Emission Rate[d]	(lb/hr)	capacity factor	(hr/yr)		(ton/yr)
Combustion Turbine (natural gas):	49.4	100%	8,760		216.4
Duct Burner (natural gas):	46.8	64%	8,760		131.2
Total Uncontrolled CO Emission Rate, ton/yr					347.6
Estimated CO Control Efficiency[g], %					85%
Controlled CO Emission Rate, ton/yr					52.1
Estimated tons of CO Controlled, ton/yr					295.4
Annual Cost per Ton CO Controlled, $/ton				$	1,856

[a] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[b] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[c] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142

[d] Annual emissions assuming the combustion turbine operates at power augmentation load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[e] Average energy cost is $0.04/kW-hr.

[f] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 164.9 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[g] 85% CO average reduction expected for typical load conditions per vendor performance data sheet.

Based on the vendor supplied cost estimates and the methodology presented in the OAQPS Control Cost Manual, the total capital investment that would be required for an oxidation catalyst system to reduce CO emissions by 85% for the combustion turbine/duct burner system is $1,462,846. The annualized operating costs for operating an oxidation catalyst system for the proposed Santa Rosa Energy Center is $548,257.

Typically, control costs are also evaluated on the cost effectiveness based on annualized costs in dollars per ton of pollutant removed. Based on the maximum amount of CO emissions that would be expected to be removed by an oxidation catalyst oxidation catalyst system for the proposed Santa Rosa Energy Center, costs are estimated to be in excess of $1,856 per ton of CO removed to achieve CO emissions reduction of 85%. For the combustion turbine contribution, the cost effectiveness is higher. The use of an oxidation catalyst system is not cost effective for the proposed Santa Rosa Energy Center system, both in terms of annualized costs and dollar per ton cost effectiveness. Oxidation catalysts for CO abatement is not BACT because it is not an economically feasible control method.

5.2.3.3 Conclusion

Based on the control evaluations above, Santa Rosa Energy LLC proposes that BACT for CO emissions from the combustion turbine be good combustion practices. The economic evaluation for the only technically feasible control technique alternative, catalytic oxidation, indicated that the control method was not economically feasible.

5.2.4 BACT for Nitrogen Oxides

During combustion, NO_x is formed through the oxidation of the fuel-bound nitrogen, referred to as fuel NO_x, and by oxidation of the nitrogen in the combustion air, referred to as thermal NO_x. The rate of both fuel NO_x and thermal NO_x formation are functions of temperature.

Nitrogen oxides control methods can be divided into two basic categories: 1) combustion control where NO_x formation is minimized, and 2) post combustion reduction where NO_x formed during combustion is reduced. NO_x formation in combustion turbines can be minimized by staging combustion, reducing the amount of combustion air available for NO_x formation, reducing the combustion temperature, or some combination thereof. Post combustion NO_x controls can reduce a portion of the NO_x emissions exiting the system by converting NO_x into nitrogen gas and water vapor.

A summary of NO_x emission entries from the RBLC search for natural gas fired combustion turbines is presented as Table 5-10. The RBLC presented entries with Dry Low NO_x Combustion, water/steam injection, selective catalytic reduction (SCR), or some combination thereof. In addition, Santa Rosa Energy LLC has identified SCONO$_X$™ and selective non-catalytic reduction (SNCR) as a potential control alternatives.

5.2.4.1 Discussion of Technical Feasibility of NO_X Control Alternatives

SCONO$_X$™

SCONO$_X$™ is a patented process by Goal Line Environmental Technologies which employs post combustion catalytic absorption to reduce emissions of CO and NO_X. A precious metal catalyst is coated with an absorption liquid. The catalyst oxidizes CO to CO_2 and NO to NO_X. The liquid coating absorbs NO_2 onto the surface of the catalyst. A dilute hydrogen reducing gas is passed across the catalyst surface and the adsorbed NO_X is released as N_2 and H_2O. Continuous regeneration of the catalyst is required.

Following is a description of the SCONO$_X$™ process provided by the vendor.

> The Oxidation/Absorption Cycle. The SCONO$_X$™ catalyst works by simultaneously oxidizing CO to CO_2 , NO To NO_2 and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating. These reactions are shown below, and are referred to as the "Oxidation/Absorption Cycle."

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2 \quad (1)$$

$$NO + \tfrac{1}{2}O_2 \rightarrow NO_2 \quad (2)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (3)$$

The CO_2 in reaction (1) and reaction (3) is exhausted up the stack. Note that during this cycle, the potassium carbonate coating reacts to form potassium nitrites and nitrates, which are then present on the surface of the catalyst. The $SCONO_X$™ catalyst becomes saturated with NO_X and must be regenerated. When all of the carbonate absorber coating on the surface of the catalyst has been reacted to nitrogen compounds, NO_X will no longer be absorbed, and the catalyst must enter the regeneration cycle.

The Regeneration Cycle. The regeneration of the $SCONO_X$™ catalyst is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. The hydrogen in this gas reacts with the nitrates and nitrites to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. This cycle is referred to as the "Regeneration Cycle," and the relevant reaction is shown below.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O_{(g)} + N_2 \quad (4)$$

Water (as steam) and elemental nitrogen are exhausted up the stack instead of NO_X, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again. There is no net gain or net loss of potassium carbonate after both the oxidation/absorption cycle and the regeneration cycle have been completed.

Because the regeneration cycle must take place in an oxygen free environment, a section of catalyst undergoing regeneration must be isolated from exhaust gases. This is accomplished using a set of louvers, one upstream of the section being regenerated and one downstream. During the regeneration cycle, these louvers close and valves open, allowing fresh regeneration gas into and spent regeneration gas out of the section. Stainless steel sealing strips on the isolation louvers provided a barrier against leaks during operation.

The Regeneration Gas Generator. Regeneration gas is produced by reacting natural gas with oxygen from ambient air. The technology for producing hydrogen from natural gas is well developed, and there are numerous reactions by which this can be accomplished.

Goal Line Technologies has reported successful testing of the SCONO$_X$™ technology at one combined cycle cogeneration installation near Los Angeles, California. The installation includes a GE 30-MW combustion turbine and supplies power to Southern California Edison. However, the proposed Santa Rosa Energy LLC equipment is a much larger, complex system. The SCONO$_X$™ technology has not been demonstrated on large combustion turbines such as the GE Frame 7F machines. The problems associated with scale-up have not been identified or addressed.

In addition, there is also concern over performance of seals for isolation of catalyst modules for regeneration. The California cogeneration test facilities operate at lower temperature than the General Electric Frame 7F. The concern is that seals operating well at lower temperatures may not be as effective at higher temperature.

The catalyst used in the SCONO$_X$ process is subject to attack from sulfur oxides from combustion of natural gas. Any sulfur oxide compounds absorbed in the liquid coating on the catalyst are not removed during regeneration and reduce the activity of the catalyst for NO_X and CO reduction. The California installation uses scrubbers to remove as much of the sulfur compounds as possible from the natural gas prior to combustion in the turbines. Goal Line Technologies is developing a process to remove sulfur compounds in the flue gas prior to the SCONO$_X$™ process. Until proven methods to remove all sulfur can be employed, there will be degradation of the catalyst over time.

Santa Rosa Energy LLC does not believe $SCONO_X$™ represents BACT because (1) the process has not been demonstrated to be technically feasible on large scale applications, or with conditions different from the California site, (2) there is only one supplier for the process (Goal Line Technologies) which limits availability of equipment and responsiveness in case of equipment failure, and (3) technical concerns which may become apparent after long-term operation of the process.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction uses an anhydrous or aqueous ammonia (NH_3) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH_3 into the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to nitrogen gas (N_2) and water vapor (H_2O) in the catalyst reactor. It is estimated that NO_x emissions from the Santa Rosa combustion turbine would be reduced to the approximate range of 6 ppm (corrected to 15% O_2) depending on the SCR system used and the operating conditions.

Typical SCR systems use base-metal catalysts with an operating temperature window of approximately 500°F to 750°F. The catalyst would have to be located within the HRSG so that its operating temperature would be within this temperature window over the entire operating range of the system The short-term and long-term steam production demands of the Sterling Fibers plant vary greatly as a result of seasonal demands, variations in daily temperatures, and varying operating conditions of the plant's processes. The variation in the steam demands of the plant will be met with the duct burners which would create difficulty in maintaining this temperature window for an SCR system. Maintaining the design or optimum NO_x emission reduction efficiency may not be achievable over the entire operating range of the system, due to the variation in steam demands from the Sterling Fibers plant.

To achieve optimum long-term NO_x reductions, the NH_3 injection rate must be carefully controlled to maintain the proper NH_3/NO_x molar ratio to minimize NH_3 emissions downstream of the catalyst, known as ammonia slip. The NH_3 supply can be aqueous or anhydrous.

SCR has been determined to be technically feasible for the combustion turbine proposed for Santa Rosa Energy Center.

Selective Non-catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) reduces NO_x using ammonia or urea injection similar to SCR, but operates at a higher temperature, typically between 1600°F and 2200°F. A catalyst is not employed to lower the activation energy of the reduction reactions. The required operating temperature window, however, is not compatible with combustion turbine exhaust temperatures. In addition, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for combustion turbine flow velocities. Therefore, SNCR technology is not technically feasible for the combustion turbine proposed for the Santa Rosa Energy Center. A search of the RBLC indicated that combustion turbines have not been permitted with SNCR systems.

Dry Low NO_x Combustors

Dry Low NO_x Combustor designs are based on the principle of lowering the reaction temperature of the combustion process and limiting the amount of excess air available during the combustion process as much as possible to reduce the occurrence of NO_x formation. The proposed combustion turbine system has been designed with a Dry Low NO_x Combustor for use during periods of natural gas combustion. At design capacity, the NO_x emissions will be reduced to 9 ppm (corrected to 15% O_2, dry) or less when firing natural gas. Dry Low NO_x Combustors are technically feasible for NO_x reduction from the combustion turbine proposed for the Santa Rosa Energy Center.

Water/Steam Injection

Injecting water or steam into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. A water injection system consists of a water treatment system, pump, water metering valves and instrumentation, injection nozzles, and piping. A steam injection system is similar to a water injection system except that steam replaces water. Steam is usually produced by a heat recovery steam generator (HRSG). The NO_x emissions associated with this type of water or steam injected gas could be reduced to 25 ppm (corrected to 15% O_2, dry) or less when firing natural gas in the combustion turbine. Water/steam injection is technically feasible for reducing NO_x emissions from the combustion turbine proposed for the Santa Rosa Energy Center.

5.2.4.2 BACT Selection for NO_X

SCR, Dry Low NO_x Combustor, and water/steam injection have been identified as technically feasible alternatives for controlling NO_x emissions from the combustion turbine proposed for the Santa Rosa Energy Center. Based on the level of reduction of NO_x emissions at design capacity for the system, these are ranked as follows:

Combustion firing

Rank	Control Option	Expected NO_x Emissions
1	SCR	±6 ppm (Range depends on operating conditions at ideal steady-state operating conditions and steam demand. The NO_x emissions could be below 6 ppm but during power augmentation and varying steam demand the NO_x emissions would be 6 ppm or higher Hence and average NO_x emission rate of 6 ppm was used for evaluation purposes.)
2	Dry Low NO_x Combustion	9 ppm 12 ppm (Power Augmentation)
3	Water/steam injection	25 ppm

The following evaluation considers energy, environmental, and economic impacts of applying SCR to control NO_x emissions for the proposed combustion turbine at the Santa Rosa Energy Center.

Energy Impacts of SCR

Utilization of an SCR system would have a negative impact on energy for the proposed Santa Rosa Energy Center system. Ammonia systems require an electric heater to vaporize the ammonia/water solution prior to injection. Therefore, the operation of an SCR system would require use of a heating system to vaporize the ammonia, as well as pumps to operate the ammonia injection system and meter the appropriate amount of NH_3, all of which would require electrical energy. A report published by Black & Veatch[1] indicates experience has shown that 2 kW/lb of contained ammonia is required for vaporization. This would result in a total utility cost for the pump, fan, and heater of 67 kW for the system for a NO_X emissions reduction to 6 ppm.

This results in an additional annual energy consumption of:

$$(67 \text{ kW})(8{,}760 \text{ hr/yr}) = 587{,}000 \text{ kW - hr/yr}$$

Performance of combustion turbines is dependent upon, among other factors, back pressure induced upon the system. An SCR catalyst system would increase the back pressure of the combustion turbine, resulting in a reduction of electricity output by 471.2 kW and a reduced operating thermal efficiency, which would in turn increase the expected fuel usage and the quantity of air emissions. This performance penalty is due to the presence of catalyst in the combustion turbine exhaust stream (not the operation of the SCR system) so that the penalty would be incurred for 8,760 hours per year. This reduction in performance results in a annual loss of energy generated from the system of:

$$(471.2 \text{ kW})(8{,}760 \text{ hr/yr}) = 4{,}127{,}712 \text{ kW-hr/yr}$$

[1] Gregory, M.G., J.R. Cochran, J.W. Anderson, L.S. Mancini, and G.A. Demuth, "Aqueous or Anhydrous? What Stanton and Other Experience Tell Us About Ammonia Selection", ICAC Forum '96, March 19-20, 1996.

Therefore, the use of an SCR system for controlling NO_x emissions from the proposed system at the Santa Rosa Energy Center would have a negative energy impact on the system of 4,714,712 kW-hrs per year.

Environmental Impacts of SCR

Use of an SCR system would require the use of ammonia. The ammonia may be either anhydrous or aqueous. Anhydrous ammonia is extremely corrosive and irritating to the skin, eyes, nose, and respiratory tract. The IDLH (Immediately Dangerous to Life and Health) level for ammonia is 300 ppm, based on a 30-minute exposure. Even at low concentrations, ammonia can be an irritant as well a nuisance for odors, with ammonia odor typically detected at concentrations as low as 5 ppm.

Ammonia can pose a number of environmental, health, and safety risks. As such, a number of regulations and standards have been developed regarding the storage and use of ammonia. The three main reasons for the promulgation of federal regulations are to establish exposure limits related to human health and safety, to define minimum design parameters to prevent chemical releases, and to structure the actions which must be taken if a release occurs.

The Santa Rosa Energy Center would require either 7,000 gallons of storage capacity for anhydrous ammonia, or 25,000 gallons of aqueous ammonia (28% NH_3 by weight) storage capacity in order to maintain a 30-day supply for an SCR system. Transportation and storage of these quantities of ammonia pose a number of health and safety risks to facility personnel and to the surrounding community, including potential accidental releases of ammonia. Accidental releases from an ammonia storage and injection system could result from operation and maintenance failures (such as faulty repairs), equipment failures (including defective equipment or leaking pipes, valves, and flanges) and process failures (due to pressure, temperature, or flow changes that result in equipment failures and/or ruptures).

The ammonia slip from the SCR system would be limited to 10 ppm at 15 percent O_2, which would result in an emission rate of 98 tons per year of ammonia to achieve an overall reduction in NO_X emissions (combustion turbine and duct burner) of 234 tons per year.

The passage of the Chemical Accidental Release Prevention legislation (Section 112 (r) of the Clean Air Act defined in 40 CFR Part 68) subjects aqueous ammonia systems with ammonia concentrations of 20 percent or greater to this regulation. The Santa Rosa Energy LLC would be required to develop and submit a Risk Management Plan (RMP) which would need to include the following three elements:

- Hazard assessment - evaluation of off-site effects of an accidental release.
- Prevention program - including safety precautions, maintenance, monitoring and employee training.
- Emergency response program - coordinating response with federal, state, and local emergency planning committees.

Along with the risks associated with ammonia storage are the risks associated with its transportation. The ammonia supply would likely be delivered via tank truck traveling the local roadways to the Santa Rosa Energy Center. It is estimated that approximately two shipments per week would be required to maintain an adequate supply of material. This would result in an increase in local vehicle truck traffic, air emissions from the vehicles, and increased risk to the community in the event of an accidental release or spill.

Each SCR system would have an estimated catalyst life of three years. The spent catalyst would be classified as a hazardous waste due to the heavy metal content of the catalyst material. Removal and replacement of the catalyst would require specially trained personnel. In addition, the catalyst material may need to be disposed of in a licensed landfill.

Economic Impacts of SCR

Annualized costs have been determined for use of an SCR system to determine the economic impacts on the proposed Santa Rosa Energy Center. The annualized costs were calculated based on the standardized procedures and algorithms from the Fourth Edition of the OAQPS Control Cost Manual (U.S. EPA, EPA 450/3-90-006). Capital costs associated with the SCR system equipment costs were based on a vendor cost estimate. Total annualized capital investment and annualized cost of operating an SCR system were calculated using algorithms from the OAQPS Control Cost Manual.

A summary of the capital costs and annualized costs associated with operating an SCR system for a NO_X emissions reduction for the combustion turbine/duct burner cogeneration system is presented in Table 5-5 and Table 5-6.

The annualized cost estimated in Table 5-6 is based on operation of the SCR at 8,760 hours per year.

Based on the vendor supplied cost estimates and the methodology presented in the OAQPS Control Cost Manual, the total capital investment that would be required for an SCR system to reduce NO_X emissions to 6 ppm for the combustion turbine/duct burner system is $2,726,213. The annualized operating costs for operating an SCR system for the proposed Santa Rosa Energy Center is $1,226,963.

Typically, control costs are also evaluated on the cost effectiveness based on annualized costs in dollars per ton of pollutant removed. Based on the maximum amount of NO_x emissions that would be expected to be removed by an SCR system for the proposed Santa Rosa Energy Center, costs are estimated to be in excess of $5,247 per ton of NO_x removed to achieve NO_X emissions of 6 ppm for the combined combustion turbine and duct burner emissions. The cost estimates for the combustion turbine alone would be higher. The use of an SCR system is not cost effective for

TABLE 5-5
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
SCR SYSTEM ANNUAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard SCR System[b]		=	$	1,400,000
Aqueous ammonia tank[c]		=	$	35,000
Equipment Cost	A	=	$	1,435,000
Instrumentation	0.10 A	=	$	143,500
Sales taxes	0.03 A	=	$	43,050
Freight	0.05 A	=	$	71,750
Purchased equipment cost, PEC	B = 1.18 A	=	$	1,693,300
Direct installation costs				
Foundations & supports	0.08 B	=	$	135,464
Handling & erection	0.14 B	=	$	237,062
Electrical	0.04 B	=	$	67,732
Piping	0.02 B	=	$	33,866
Insulation	0.01 B	=	$	16,933
Painting	0.01 B	=	$	16,933
Direct installation costs	0.30 B	=	$	507,990
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	2,201,290
Indirect Costs (installation)				
Engineering	0.10 B	=	$	169,330
Construction and field expenses	0.05 B	=	$	84,665
Contractor fees	0.10 B	=	$	169,330
Start-up	0.02 B	=	$	33,866
Performance test	0.01 B	=	$	16,933
Contingencies	0.03 B	=	$	50,799
Total Indirect Costs, IC	0.31 B	=	$	524,923
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	2,726,213

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 8 December 1997. Estimate does not include the aqueous ammonia tank.

[c] Estimated based on the size required for a 30-day supply for the combustion turbine system assuming power augmentation load at 68°F ambient temperature. Tank cost is estimated as $35,000 for a 25,000-gallon carbon-steel tank.

TABLE 5-6
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
SCR SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS	COST
Direct Annual Cost, DC		
Operating Labor		
Operator	0.5 hr/shift x 3 shift/day x 365 day/yr x $ 25 /hr	$ 13,688
Supervisor	15% of operator	$ 2,053
Operating Materials		
Aqueous ammonia (28%)[a]	206.6 lb NH_3/hr x 8,760 hr/yr x $ 0.130 /lb NH_3	$ 235,319
Maintenance		
Labor	0.5 hr/shift x 3 shift/day x 365 day/yr x $ 25 /hr	$ 13,688
Material	100% of maintenance labor	$ 13,688
Replacement parts, catalyst (3 year life)		
Catalyst cost[b]	0.381 [c] x $900,000 x 1.08	$ 370,382
Spent catalyst removal cost	0.381 [c] x $ 30,000	$ 11,432
Utility Costs		
Electricity for pump, fan, and heater[d]	67 kW x 8,760 hr/yr x $ 0.04 /kW-hr[e]	$ 23,477
Total DC		$ 683,726
Indirect Annual Costs, IC		
Overhead	60% of sum of operating, supv., & maint. labor, & maint. materials = 0.6(13687.5 + 2053.125 + 13687.5 + 13687.5)	$ 25,869
Administrative charges	2% of Total Capital Investment = 0.02 ($2726213)	$ 54,524
Property tax	1% of Total Capital Investment = 0.01 ($2726213)	$ 27,262
Insurance	1% of Total Capital Investment = 0.01 ($2726213)	$ 27,262
Capital recovery[f]	0.142 [2726213 - 30000 - 900000(1.08)]	$ 245,489
Total IC		$ 380,407
Performance Penalty[g]	471.2 kW x 8,760 hr/yr x $ 0.04 /kW-hr[e]	$ 165,108
Total Annual Cost		$ 1,229,241

Uncontrolled NOx Emission Rate[h]	(lb/hr)	capacity factor	(hr/yr)	(ton/yr)
Combustion Turbine (natural gas):	86.1	PWR AUG	8,760	377.1
Duct Burner (natural gas):	46.8	64%	8,760	131.2
Total Uncontrolled NOx Emission Rate, ton/yr				508.3
Estimated NOx Control Efficiency[i], %				46%
Controlled NOx Emission Rate, ton/yr				274.5
Estimated tons of NOx Controlled, ton/yr				233.8
Annual Cost per Ton NOx Controlled, $/ton				$ 5,257

[a] Cost based on information from Chemical Market Reporter, February 9, 1998.

[b] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[c] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[d] Per Black & Veatch Publication, 2 kW per pound of contained ammonia are required for vaporizing aqueous ammonia, and 5 kW are required to run the pump and fan. 2 kW/lb x 0.28 lb NH_3/lb x 110 lb/hr + 5 kW/hr = 67 kW/hr.

[e] Average energy cost is $0.04/kW-hr.

[f] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142.

[g] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 471.2 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[h] Annual emissions assuming the combustion turbine operates at power augmentation load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[i] 46% NO_X reduction expected for typical load conditions per vendor performance data sheet.

the proposed Santa Rosa Energy Center system, both in terms of annualized costs and dollar per ton cost effectiveness.

Summary of Impacts from SCR

SCR is technically feasible for controlling NO_x emissions from combustion turbines firing natural gas. However, use of SCR technology on the proposed combustion turbine for the Santa Rosa Energy Center would impose negative energy, environmental, and economic impacts. Use of an SCR system would result in a negative energy impact on additional energy usage as well as reduce the amount of energy produced by the system up to 3,653,000 kW-hrs per year. Negative environmental impacts from using an SCR system include:

- Potential additional risks to the community from transportation and storage of an extremely hazardous substance (ammonia),
- Potential health and safety risks to the operating personnel of the facility,
- Potential emissions of ammonia due to the ammonia slip that are inherent to SCR systems, and
- Potential disposal of spent catalyst material as hazardous waste material due to the heavy metals in the catalyst material

Use of an SCR system to reduce NO_x emissions would require a total capital investment of over $2,700,000 and would impose an additional annualized cost of nearly $1,226,963 per year to the facility. The cost-effectiveness for an SCR system for the combustion turbine and duct burner is over $5,247 per ton of NO_x removed.

5.2.4.3 Conclusion

As demonstrated above, the use of SCR is not considered to be BACT for this project due to potential negative energy and environmental impacts, as well as the unreasonable costs associated with an SCR system. Santa Rosa Energy LLC proposes that BACT for NO_x emissions is the use of the Dry Low NO_x Combustor which will limit NO_x emissions to 9 ppm (corrected to 15%) and 12 ppm (corrected to 15%) during power augmentation mode.

5.2.5 BACT for Other Regulated Pollutants

Based on the emissions inventories provided in Section 3, the level of emissions of other regulated pollutants including lead and hazardous air pollutants listed in the Clean Air Act pollutant of 1990 (in this case, beryllium and heavy metals) are very low. The only known mechanism for generation of other regulated pollutants based on vendor and US EPA provided emission factors for the combustion turbine is when the combustion turbine fires No. 2 fuel oil. Given that only natural gas will be fired, add-on controls for other regulated pollutants is not required to be evaluated

5.3 BACT ANALYSIS FOR THE HEAT RECOVERY STEAM GENERATOR DUCT BURNER (HRSG)

BACT analyses for the proposed Heat Recovery Steam Generator Duct Burner (HRSG) are required for the following regulated pollutants: VOC, PM/PM_{10}, CO, and NO_x. As part of the evaluation, a review of the RBLC for natural gas fired duct burners was conducted and the findings are included in Table 5-7 through Table 5-10 at the end of this section. The RBLC entries include duct burners with add-on controls as well as duct burners utilizing good combustion practices to minimize emissions.

Based upon the information supplied in the RBLC and subsequent investigation, it appears that none of the duct burners listed incorporate any add-on controls for PM/PM_{10}. Only two of the RBLC entries included in Table 5-7 had add-on controls for VOC emission, one of the RBLC entries had an oxidation catalyst for CO and low NO_x burners and several SCR were listed for NO_x. All other sources utilized good combustion practices to meet the BACT levels identified.

In order to follow the "top-down" BACT analysis procedure, Santa Rosa Energy LLC has evaluated all potential control techniques to determine if such processes could be considered BACT for the proposed HRSG with duct burners.

5.3.1 BACT for Volatile Organic Compounds (VOC)

The RBLC search for natural gas fired duct burners was conducted to obtain determinations for VOC emissions. A summary of the determinations are presented in Table 5-7. The RBLC presented determinations for furnace design and catalytic oxidation add-on control technology as BACT for natural gas fired duct burners. Santa Rosa Energy LLC has identified thermal oxidization, catalytic oxidation, adsorption, and condensation in addition to employment of good combustion practices to the duct burners as potential emission control techniques that have been applied for reducing VOC emissions.

5.3.1.1 Discussion of Technical and Economic Feasibility

The control techniques considered for VOC emissions from the duct burner are identical to those employed for the combustion turbine. The assessment of technical and economical feasibility of each method is also the same due to the similarities in the exhaust gas streams. To simplify the permit application, the information was not repeated here. Refer to Section 5.2.1 for a detailed discussion.

5.3.1.2 Conclusion

Based on the control evaluation above, Santa Rosa Energy LLC proposes BACT to be the use of good combustion practices. The only other technically feasible control alternative, oxidation catalyst, was determined not to be economically feasible.

5.3.2 BACT for Particulate Matter

A search of the RBLC for natural gas fired duct burners was performed for PM/PM_{10} BACT determinations, a summary of which is presented in Table 5-8. The RBLC determinations included no add-on control technologies. The determinations did include control technologies such as combustion of clean fuels (e.g., firing only natural gas, limiting the sulfur content of the fuel).

5.3.2.1 Discussion of Technical and Economic Feasibility

Santa Rosa Energy LLC identified baghouses, electrostatic precipitators, and scrubbers, and combustion of clean fuels as emission controls used to remove PM/PM_{10} in gaseous streams. A similar evaluation was made for the combustion turbine PM/PM_{10} emissions and is not repeated here due to the similarities in the exhaust gas characteristics. The conclusions were also the same. Refer to Subsection 5.2.2 for a detailed discussion.

5.3.2.2 Conclusion

Based on the technology evaluation, the proposed BACT is combustion of clean fuels. No economic analysis is presented because only technically feasible controls were selected as BACT.

5.3.3 BACT for Carbon Monoxide

A search of the RBLC for natural gas-fired duct burners was performed for CO BACT determinations, a summary of which is presented in Table 5-9. The RBLC determinations included control technologies such as furnace design and the use of oxidation catalysts.

5.3.3.1 Discussion of Technical and Economic Feasibility

Santa Rosa Energy LLC identified oxidation catalysts as potential add-on emission control for CO. The same evaluation applicable to the combustion turbine applies to the duct burner as both exhaust gas streams have similar characteristics. The assessment of technical and economic feasibility of each method is also the same. To simplify the permit application, the information was not repeated here. Refer to Section 5.2.3 for a detailed discussion.

5.3.3.2 Conclusion

Based on the control evaluation above, Santa Rosa Energy LLC proposes BACT for the control of CO emissions to be good combustion practices. The only other technically feasible control alternative, oxidation catalyst, was determined not to be economically feasible.

5.3.4 BACT for Oxides of Nitrogen

A search of the RBLC for natural gas-fired duct burners was performed for NO_x BACT determinations, a summary of which is presented on Table 5-10. The RBLC determinations included the use of low NO_x burners, SCR, or a combination of both.

5.3.4.1 Discussion of Technical and Economic Feasibility

Santa Rosa Energy LLC identified low NO_x burners, $SCONO_x$™, SCR, and SNCR as potential emission controls for NO_x removal. A similar evaluation was made for the combustion turbine emissions and is not repeated here. Refer to Section 5.2.4 for a detailed discussion. The only exception is with respect to the type of fuels fired. Only natural gas will be fired in the duct burner.

5.3.4.2 Conclusion

Based on the control evaluation above, Santa Rosa Energy LLC proposes BACT to be the use of low NO_x burners in the duct burner. The only other technically feasible control alternative, SCR, was determined to have potential negative energy and environmental impacts, and determined to be not economically feasible. Therefore, low NO_x burners will be used in the duct burner.

5.4 BACT FOR THE COGENERATION FACILITY

The BACT evaluation presented above for VOC, PM/PM_{10}, CO, and NO_x address the combustion turbine and the duct burner separately. Santa Rosa Energy LLC believes that the same conclusions are valid for the cogeneration facility in total. The combustion turbine exhaust gases are used as the combustion air for its associated duct burner. NO_x emissions from the duct burner will be minimized through the use of low NO_x burners.

TABLE 5-7
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - VOC CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Algonquin Gas Transmission Co.	Burrillville, Rhode Island	07/31/91	Turbine, Gas (2)	49	VOC	P	Cood Combustion Practices	BACT-OTHER	0.016			0
Anitec Cogen Plant	Binghamton, New York	07/07/93	GE LM5000 Combined Cycle Gas Turbine EP#00001	451	VOC	N	No controls	BACT-OTHER	0.008		3.0	0
Anitec Cogen Plant	Binghamton, New York	07/07/93	Duct Burner EP#00001	70	VOC	N	No controls	BACT-OTHER	0.02		1.2	0
Auburndale Power Partners, LP	Auburndale, Florida	12/14/92	Turbine, Gas	1214	VOC	P	Good combustion practices	BACT-PSD	0.0049		6.0	0
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Turbine, Combustion Gas	474	VOC	P	Good Combustion	BACT-PSD			5.0	0
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Duct Burner	129	VOC	P	Good Combustion	BACT-PSD			10.0	0
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Turbine, Combustion	1175	VOC	P	Furnace Design	BACT-PSD			2.3	91
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Burner, Duct	197	VOC	P	Furnace Design	BACT-PSD			5.9	91
Blue Mountain Power, LP	Richland, Pennsylvania	07/31/96	Combustion Turbine with Heat Recovery Boiler	153 MW	VOC	A	Oxidation Catalyst	LAER		4		12
BMW Manufacturing Corporation	Greer, South Carolina	01/07/94	Turbine, Natural Gas	54.5 MW	VOC	N	No controls	LAER			77.86 lb/day	
Brush Cogeneration Partnership	Brush, Colorado	05/01/94	Turbine	350	VOC	N	No controls	OTHER			26.7 tpy	0
Bucknell University	Lewisburg, Pennsylvania	11/26/97	Natural Gas Fired Solar Taurus Turbine	5MW	VOC	P	Good Combustion Practices	BACT-OTHER			25	
Carolina Power & Light	Goldsboro, North Carolina	04/11/96	4 GE PG7231 FA Simple Cycle Turbines	1907.6	VOC	P	Combustion Control	BACT-PSD	0.0015		2.8	0
Carolina Power and Light Co.	Darlington, South Carolina	09/23/91	Turbine, I.C.	80 MW	VOC	N	No control	BACT-PSD			10.0	0
CNG Transmission	Washington Court House, Ohio	08/12/92	Turbine, Natural Gas (3)	5500 HP	VOC	P	Fuel Spec: Use of natural gas	OTHER	0.1 g/hp-hr			0

TABLE 5-7
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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Colorado Power Partnership	Brush, Colorado	05/01/92	Two Natural gas turbines	385	VOC	N	No controls	OTHER			35.2 tpy	0
CSW Nevada, Inc.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	VOC	P	Fuel Spec: Natural Gas	BACT-PSD			13.0	0
Duke Power Co. Lincoln Combustion Turbine Station	Lowesville, North Carolina	12/20/91	Turbine, Combustion	1313	VOC	P	Combustion Control	BACT-PSD			2.0	0
East Kentucky Power Cooperative	Clark, Kentucky	03/24/93	Turbines (5), #2 Fuel Oil and Natural Gas	1492	VOC	P	Proper Combustion Techniques	BACT-OTHER			26.0	0
Fleetwood Cogeneration Associates	Fleetwood, Pennsylvania	04/22/94	GE LM6000 Turbine with Waste Heat Boiler	360	VOC	P	Good Combustion Practices	BACT-OTHER		2	4.4	0
Florida Power and Light	Lavogrome Repowering Station, Florida	03/14/91	Turbines, Gas, 4 Each	240 MW	VOC	P	Combustion Control	BACT-PSD		1		0
Florida Power and Light	N. Palm Beach, Florida	06/05/91	Turbines, Gas, 4 Each	400 MW	VOC	P	Combustion Control	BACT-PSD		1.6		0
Florida Power Corporation Polk County Site	Bartow, Florida	02/25/94	Turbine, Natural Gas (2)	1510	VOC	P	Good Combustion Practices	BACT-PSD		7	10.4	0
Fulton Cogen Plant	Fulton, New York	09/15/94	GE LM500 Turbine	500	VOC	N	No controls	BACT-OTHER	0.004		2	0
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbine, Facility	1331 13x10^7 scf/yr	VOC	P	Good Combustion Practices	BACT-PSD	0.0146		97 1 tpy	0
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbines (2) [Each with a duct burner]	1.51x10^9 scf/yr	VOC	P	Good Combustion Practices	BACT-PSD	0.0146		22	0
Grays Ferry Co. Generation Partnership	Philadelphia, Pennsylvania	11/04/92	Turbine (Natural Gas & Oil) [Emission limits are total for entire facility]	1150	VOC	P	Combustion	BACT-OTHER	0.0033			0
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	GE Frame 6 Gas Turbine	533	VOC	N	No controls	BACT-OTHER	0.01		5.0	0
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	Duct Burner	30	VOC	N	No controls	BACT-OTHER	0.06		1.8	0
International Paper	Mansfield, Louisiana	02/24/94	Turbine/HRSG, Gas Cogen	338	VOC	P	Combustion Controls, Fuel Selection	BACT			3.6	0

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COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Turbine, Stationary (Gas-Fired)	40 MW	VOC	P	Design	BACT-PSD			8.3	0
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Duct Burners	Unknown	VOC	P	Design	BACT-PSD			0.8	0
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	GE Frame 6 Gas Turbine	498	VOC	N	No controls	BACT-OTHER	0.009		5	0
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	Duct Burner	44	VOC	N	No controls	BACT-OTHER	0.029		15.8	Emission rates represent GT and DB combined
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Turbine, Combustion	650	VOC	P	Combustion Controls	BACT-OTHER	0.007			0
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Duct Burner	90	VOC	P	Combustion Control	BACT-OTHER	0.09			0
Kamine/Besicorp Carthage L.P.	Carthage, New York	01/18/94	GE Frame 6 Gas Turbine	491	VOC	N	No controls	BACT-OTHER	0.009		5	0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	GE Frame 6 Gas Turbine	500	VOC	N	No controls	BACT-OTHER	0.008		4	0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	Duct Burner	90	VOC	N	No controls	BACT-OTHER	0.1		9	0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Siemens V64.3 Gas Turbine (EP#00001)	650	VOC	N	No controls	BACT-OTHER	0.007		4.6	0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Duct Burner	90	VOC	N	No controls	BACT-OTHER	0.09		8.1	0
Kentucky Utilities Company	Mercer, Kentucky	03/10/92	Turbine, #2 Fuel Oil/Natural Gas (8)	1500	VOC	P	Combustion Control	BACT-PSD			20.4	0
Lakewood Cogeneration, L.P.	Lakewood Township, New Jersey	04/01/91	Turbines (Natural Gas) (2)	1190	VOC	P	Turbine design	OTHER	0.0046			0
Lockport Cogen Facility	Lockport, New York	07/14/93	Six GE Frame 6 Turbines	423.9	VOC	N	No controls	BACT-OTHER	0.012		5.0	0

TABLE 5-7
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - VOC CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Lockport Cogen Facility	Lockport, New York	07/14/93	Three Duct Burners	94.1	VOC	N	No controls	BACT-OTHER	0.1		9.4	0
LSP-Cottage Grove, L.P.	Cottage Grove, Minnesota	03/01/95	Combustion Turbine/Generator	1970	VOC	P	Fuel Selection; Good Combustion	BACT-PSD			19	70
Megan-Racine Associates, Inc	Canton, New York	08/05/89	GE LM5000-N Combined Cycle Gas Turbine	401	VOC	N	No controls	BACT-OTHER	0.02		8.0	0
Mid-Georgia Cogen.	Kathleen, Georgia	04/03/96	Combustion Turbine (2), Natural Gas	116 MW	VOC	P	Complete combustion	BACT-PSD		6		0
Muddy River L.P	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	VOC	P	Fuel Spec: Natural Gas	BACT-PSD			14	0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	VOC	N	No controls	BACT-PSD		5		0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	VOC	N	No controls	BACT-PSD		5		0
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	06/09/93	Two Westinghouse CW251/B-12 Combustion Turbines	617	VOC	P	Turbine design	BACT-PSD	0.005			0
Northern Consolidated Power	North East, Pennsylvania	05/03/91	Turbines, Gas, 2	34.6 KW	VOC	P	Oxidation catalyst	BACT-OTHER		105		50
Northern States Power Company	Sioux Falls, South Dakota	09/02/92	Turbine Simple Cycle, 4 Each	129 MW	VOC	P	Good Combustion Techniques	BACT-PSD		6		0
Northwest Pipeline Corporation	La Plata "B" Station, Colorado	05/29/92	Burners, Duct, Coen	29	VOC	N	No Controls	OTHER			1.6	0
Orange Cogeneration LP	Bartow, Florida	12/30/93	Turbine, Natural Gas, 2	368.3	VOC	P	Good Combustion	BACT-PSD		10		0
Orlando Utilities Commission	Titusville, Florida	11/05/91	Turbine, Gas, 4 Each	35 MW	VOC	P	Combustion control	BACT-PSD		7		0

TABLE 5-7
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - VOC CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Patowmack Power Partners, Limited Partnership	Leesburg, Virginia	09/15/93	Turbine, Combustion, Siemens Model V84 2, 3	$10.2x10^{9}$ scf/yr	VOC	P	Good Combustion Operating Practices	BACT-PSD			8	0
Phoenix Power Partners	Greely, Colorado	05/11/93	Generator, Steam, With Duct Burner	50	VOC	P	Fuel Spec: Natural gas combustion	BACT-OTHER			24.09 tpy	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Westinghouse W501D5 Turbines	1400	VOC	N	No controls	BACT-OTHER	0.002		2.5	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Duct Burners	214.1	VOC	N	No controls	BACT-OTHER	0.016		2.6	0
Saguaro Power Company	Henderson, Nevada	06/17/91	2 GE F-6 Turbines	34.5 MW	VOC	A	Combustion System	LAER			0.8	0
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two GE Frame 7EA Model Turbines	1123	VOC	P	Oxidation catalyst	BACT-OTHER	0.0045			0
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two Duct Burners	553	VOC	P	Oxidation catalyst	BACT-OTHER	0.0011			0
Savannah Electric and Power Co.	Effingham, Georgia	02/12/92	Turbines, 8	1032	VOC	P	Fuel Spec: Low sulfur fuel	BACT-PSD	0.003			0
SC Electric and Gas Company - Hagood Station	Charleston, South Carolina	12/11/89	Internal Combustion Turbine	110 MW	VOC	P	Good Combustion Practices	BACT-PSD			10	0
South Mississippi Electric Power Assoc.	Mosell, Mississippi	04/09/96	Combustion Turbine, Combined Cycle	1299	VOC	P	Good Combustion Controls	BACT-PSD		5.2		0
Southern California Gas	Wheeler Ridge, California	10/29/91	Turbines, Gas-fired	47.64	VOC	A	Oxidation Catalyst	BACT-PSD		1.94	0.35	50
TBG Cogeneration Plant	Bethpage, New York	08/05/90	GE LM 2500 Gas Turbine	214.9	VOC	N	No controls	BACT-OTHER	0.008		2.9	0
Thermo Industries, LTD.	Ft. Lupton, Colorado	02/19/92	Turbines, Gas Fired, 5 Each (Each with duct burner @ 240 MMBtu/hr)	246	VOC	N	None	OTHER			16.7	0
Trigen Mitchel Field	Hempstead, New York	04/16/93	GE Frame 6 Gas Turbine	424.7	VOC	N	No controls	BACT-OTHER	0.011		4.5	0
Trigen Mitchel Field	Hempstead, New York	04/16/93	Duct Burner	195.3	VOC	N	No control	BACT-OTHER	0.035		5.8	0

TABLE 5-7
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - VOC CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
WEPCU, Paris Site	Paris, Wisconsin	08/29/92	Turbines, Combustion (4)	Unknown	VOC	P	Good Combustion Practices	BACT-PSD			9	0
West Campus Cogeneration Company	College Station, Texas	05/02/94	2 Gas Turbines [Information represents the 2 turbines combined]	75.3 MW	VOC	P	Internal Combustion Controls	BACT-PSD			38 tpy	0
Bucknell University	Lewisburg, Pennsylvania	11/26/97	Natural Gas Fired Solar Taurus Turbine	5MW	VOC	P	Good Combustion Practices	BACT-OTHER			25	

[a] Rated heat input for *each* combustion unit unless otherwise noted.

[b] RBLC Control Method Codes are as follows:

A = Add-on control equipment
N = No feasible controls
P = Pollution prevention techniques, e.g., any required process modification, change in raw material, or management practice designed to decrease or prevent emissions.
ND = No determination was made.

TABLE 5-8
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - PM/PM10 CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (gr/dscf)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Anitec Cogen Plant	Binghamton, New York	07/07/93	GE LM5000 Combined Cycle Gas Turbine EP#00001	451	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.1% by weight	BACT-OTHER	0.005		2.0	0
Anitec Cogen Plant	Binghamton, New York	07/07/93	Duct Burner EP#00001	70	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.1% by weight	BACT-OTHER	0.007		0.5	0
Auburndale Power Partners, LP	Auburndale, Florida	12/14/92	Turbine, Gas	1214	PM	P	Good combustion practices	BACT-PSD	0.0136		10.0	0
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Turbine, Combustion Gas	474	TSP/PM10	P	Fuel Spec: Clean burn fuel	BACT-PSD	0.0053		2.5	0
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Duct Burner	129	TSP/PM10	P	Fuel Spec: Clean burn fuel	BACT-PSD	0.0054		0.7	0
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Turbine, Combustion	1175	PM/PM10	P	Fuel Spec: Clean burn fuel	BACT-PSD	0.005			91
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Burner, Duct	197	PM/PM10	P	Fuel Spec: Clean burn fuel	BACT-PSD	0.05			91
BMW Manufacturing Corporation	Greer, South Carolina	01/07/94	Turbine, Natural Gas	54.5 MW	PM10	N	No controls	BACT-PSD			3.79 tpy	0
Brush Cogeneration Partnership	Brush, Colorado	05/01/94	Turbine	350	PM/PM10	N	No controls	OTHER			9.9 tpy	0
Carolina Power & Light	Goldsboro, North Carolina	04/11/96	4 GE PG7231 FA Simple Cycle Turbines	1907.6	PM/PM10	P	Combustion Control	BACT-PSD	0.0048		9.0	0
Carolina Power and Light	Darlington, South Carolina	08/31/94	Stationary Gas Turbine	1520	PM	P	Proper operation to achieve good combustion	BACT-PSD			5.9	0
Carolina Power and Light Co.	Darlington, South Carolina	09/23/91	Turbine, I.C.	80 MW	PM	N	No controls	BACT-PSD			15.0	0
Charles Larsen Power Plant	Lakeland, Florida	07/25/91	Turbine, Gas, 1 Each	80 MW	PM	P	Combustion Control	BACT-PSD	0.006			0
CNG Transmission	Washington Court House, Ohio	08/12/92	Turbine, Natural Gas (3)	5500 HP	PM	P	Fuel Spec: Use of natural gas	OTHER	0.035			0
Colorado Power Partnership	Brush, Colorado	05/01/92	Two Natural gas turbines	385	PM/PM10	N	No controls	OTHER			12.4 tpy	0
CSW Nevada, Inc.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	PM10	P	Fuel Spec: Natural Gas	BACT-PSD			17.0	0
Duke Power Co. Lincoln Combustion Turbine Station	Lowesville, North Carolina	12/20/91	Turbine, Combustion	1313	PM10	P	Combustion Control	BACT-PSD			5.0	0
East Kentucky Power Cooperative	Clark, Kentucky	03/24/93	Turbines (5), #2 Fuel Oil and Natural Gas	1492	PM/PM10	P	Proper Combustion Techniques	BACT-OTHER			54.0	0

TABLE 5-8
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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (gr/dscf)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Fleetwood Cogeneration Associates	Fleetwood, Pennsylvania	04/22/94	GE LM6000 Turbine with Waste Heat Boiler	360	PM	N	No controls	BACT-OTHER			8	0
Florida Power and Light	Lavogrome Repowering Station, Florida	03/14/91	Turbines, Gas, 4 Each	240 MW	PM	P	Combustion Control	BACT-PSD			15.4	0
Florida Power and Light	N. Palm Beach, Florida	06/05/91	Turbines, Gas, 4 Each	400 MW	PM	P	Combustion Control	BACT-PSD			18	0
Florida Power Corporation Polk County Site	Bartow, Florida	02/25/94	Turbine, Natural Gas (2)	1510	PM	P	Good Combustion Practices	BACT-PSD	6.00E-03		9	0
Fulton Cogen Plant	Fulton, New York	09/15/94	GE LM500 Turbine	500	PM/PM10	P	Fuel Spec: Sulfur Content < 0.3%	BACT-OTHER	0.025		12	0
Gainsville Regional Utilities	Gainsville, Florida	04/11/95	Simple Cycle Combustion Turbine, Gas/No. 2 Oil Back-up	74 MW	PM	P	Fuel Spec: Low sulfur fuels	BACT-PSD			7	0
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbine, Facility	1331.13x10^7 scf/yr	TSP/PM10	P	Fuel Spec: Clean burning fuel	BACT-PSD	0.0053		50.6 tpy	0
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbines (2) [Each with a duct burner]	1.51x10^9 scf/yr	TSP/PM10	P	Fuel Spec: Clean burning fuel	BACT-PSD	0.0003		8	0
Grays Ferry Co. Generation Partnership	Philadelphia, Pennsylvania	11/04/92	Turbine (Natural Gas & Oil) [Emission limits are total for entire facility]	1150	PM	P	Dry Low NO_x Burner, Combustion Control	BACT-OTHER	0.1			0
Hartwell Energy Limited Partnership	Hartwell, Georgia	07/28/92	Turbine, Gas Fired (2 Each)	1817	PM	P	Fuel Spec: Clean burning fuels	BACT-PSD	0.0064			0
Hartwell Energy Limited Partnership	Hartwell, Georgia	07/28/92	Turbine, Gas Fired (2 Each)	1840	PM	P	Fuel Spec: Clean burning fuels	BACT-PSD	0.0154			0
Indeck Energy Company	Silver Springs, New York	05/12/93	GE Frame 6 Gas Turbine	491	PM/PM10	N	No controls	BACT-OTHER	0.006		2.5	0
Indeck Energy Company	Silver Springs, New York	05/12/93	Duct Burner EP#00001	100	PM/PM10	A	Fabric Collector	BACT	0.01		1.0	99
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	GE Frame 6 Gas Turbine	533	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.27% by weight	BACT-OTHER	0.008		5.0	0
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	Duct Burner	30	PM/PM10	P	Fuel Spec. Natural gas only	BACT-OTHER	0.01		0.3	0
Indeck-Yerkes Energy Services	Tonawanda, New York	06/24/92	GE Frame 6 Gas Turbine (EP#00001)	432.2	PM/PM10	N	No controls	BACT-OTHER	0.007		2.5	0
Indeck-Yerkes Energy Services	Tonawanda, New York	06/24/92	Duct Burner	20	PM/PM10	N	No Controls-Natural gas only	BACT-OTHER	0.005		0.1	0
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Turbine, Stationary (Gas-Fired)	40 MW	PM/PM10	P	Fuel Specification	BACT-PSD	0.01			0

TABLE 5-8
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - PM/PM10 CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(gr/dscf)	(lb/hr)	CONTROL EFFICIENCY
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Duct Burners	Unknown	PM/PM10	P	Fuel Specification	BACT-PSD			2.6	0
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	GE Frame 6 Gas Turbine	498	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.20% S by weight.	BACT-OTHER	0.005		3	0
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	Duct Burner	44	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.20% S by weight	BACT-OTHER	0.005		3	Emission rates represent GT and DB combined
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Turbine, Combustion	650	PM/PM10	P	Combustion Controls	BACT-OTHER	0.008			0
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Duct Burner	90	PM/PM10	P	Combustion Control	BACT-OTHER	0.05			0
Kamine/Besicorp Carthage L.P.	Carthage, New York	01/18/94	GE Frame 6 Gas Turbine	491	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.20% by weight	BACT-OTHER	0.005		3	0
Kamine/Besicorp Corning L.P.	South Corning, New York	11/05/92	Turbine, Combustion	653	PM/PM10	P	Combustion control	BACT-OTHER	0.008			0
Kamine/Besicorp Corning L.P.	South Corning, New York	11/05/92	Duct Burner	90	PM/PM10	P	Combustion control	BACT-OTHER	0.05			0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	GE Frame 6 Gas Turbine	500	PM/PM10	P	Fuel Spec: Natural Gas	BACT-OTHER	0.006		3	0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	Duct Burner	90	PM/PM10	P	Fuel Spec: Fuel Oil < 0.20% S by weight. Fuel oil limited to 25% of the time and 10.44 million gal/yr	BACT-OTHER	Included with turbine emission limits			0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Siemens V64.3 Gas Turbine (EP#00001)	650	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.15% by weight	BACT-OTHER	0.008		5.8	0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Duct Burner	90	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.15% by weight	BACT-OTHER	0.05		4.5	0
Kentucky Utilities Company	Mercer, Kentucky	03/10/92	Turbine, #2 Fuel Oil/Natural Gas (8)	1500	PM/PM10	P	Combustion Control	BACT-PSD			67	0
Kissimmee Utility Authority	Intercession City, Florida	04/07/93	Turbine, Natural Gas	869	PM	P	Good Combustion Practices	BACT-PSD			7	0
Kissimmee Utility Authority	Intercession City, Florida	04/07/93	Turbine, Natural Gas	367	PM	P	Good Combustion Practices	BACT-PSD			9	0
Lake Cogen Limited	Umatilla, Florida	11/20/91	Turbine, Gas, 2 Each	42 MW	PM/PM10	P	Combustion Control, Fuel Spec: Clean Fuel	BACT-PSD	0.0065			0

TABLE 5-8
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SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - PM/PM10 CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT(a) (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE(b)	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(gr/dscf)	(lb/hr)	CONTROL EFFICIENCY
Lake Cogen Limited	Umatilla, Florida	11/20/91	Duct Burner, Gas	150	PM/PM10	P	Fuel Spec: Limited to natural gas	BACT-PSD	0.006			0
Lakewood Cogeneration, L.P.	Lakewood Township, New Jersey	04/01/91	Turbines (Natural Gas) (2)	1190	PM/PM10	P	Turbine design	BACT-OTHER	0.023			0
Lederle Laboratories	Pearl River, New York	09/15/94	(2) Gas Turbines (EP #S 00101&102)	110	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.30% by weight	BACT-OTHER			5	Emission rates represent GT and DB combined
Lederle Laboratories	Pearl River, New York	09/15/94	(2) Duct Burners (EP #S 00101&102)	99	PM/PM10	N	Fuel Spec: Sulfur content not to exceed 0.30% by weight	BACT-OTHER			5	Emission rates represent GT and DB combined
Lockport Cogen Facility	Lockport, New York	07/14/93	Six GE Frame 6 Turbines	423.9	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.20% by weight	BACT-OTHER	0.006		2.5	0
Lockport Cogen Facility	Lockport, New York	07/14/93	Three Duct Burners	94.1	PM/PM10	P	Fuel Spec: Natural gas only	BACT-OTHER	0.006		0.6	0
Lordsburg L. P.	Lordsburg, New Mexico	06/18/97	N.G. Fired Turbine	100 MW	PM	P	High Comb. Efficiency	BACT-PSD			5.3	0
LSP-Cottage Grove, L.P.	Cottage Grove, Minnesota	03/01/95	Combustion Turbine/Generator	1970	PM	P	Fuel Selection; Good Combustion	BACT-PSD			10.7	70
Mead Coated Board, Inc.	Phenix City, Alabama	03/12/97	Turbine and Duct Burners (Combined)	568	PM/PM10	P	Efficient operation of turbine	BACT-PSD			2.5	0
Megan-Racine Associates, Inc.	Canton, New York	08/05/89	GE LM5000-N Combined Cycle Gas Turbine	401	PM/PM10	N	No controls	BACT-OTHER	0.02		12.0	0
Megan-Racine Associates, Inc.	Canton, New York	08/05/89	Duct Burner	40	PM/PM10	P	Fuel Spec: Natural gas only	BACT-OTHER	Refer to NOTE below.			0
Mid-Georgia Cogen	Kathleen, Georgia	04/03/96	Combustion Turbine (2), Natural Gas	116 MW	PM	P	Clean Fuel	BACT-PSD			18	0
Muddy River L.P.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	PM10	P	Fuel Spec: Natural Gas	BACT-PSD			17	0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	PM	N	No controls	BACT-PSD	0.005			0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	PM	N	No controls	BACT-PSD	0.01			0
Nevada Power Company, Harry Allen Peaking Plant	Las Vegas, Nevada	09/18/92	Combustion Turbine Electric Power Generation (8)	75 MW	PM	P	Precision Control For The Combustor	BACT-PSD			5.5 tpy	0
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	06/09/93	Two Westinghouse CW251/B-12 Combustion Turbines	617	TSP	P	Turbine design	BACT-OTHER	0.006		3.84	0
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	06/09/93	Two Westinghouse CW251/B-12 Combustion Turbines	617	PM10	P	Turbine design	BACT-PSD	0.006		3.84	0

TABLE 5-8
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - PM/PM10 CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (gr/dscf)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Northern States Power Company	Sioux Falls, South Dakota	09/02/92	Turbine Simple Cycle, 4 Each	129 MW	PM	P	Fuel Spec: Natural gas as primary fuel	BACT-PSD			12	0
Northwest Pipeline Corporation	La Plata "B" Station, Colorado	05/29/92	Burners, Duct, Coen	29	PM	N	No Controls	OTHER			0.4	0
Orange Cogeneration LP	Bartow, Florida	12/30/93	Turbine, Natural Gas, 2	368.3	PM	P	Good Combustion	BACT-PSD			5	0
Patowmack Power Partners, Limited Partnership	Leesburg, Virginia	09/15/93	Turbine, Combustion, Siemens Model V84.2, 3	$10.2x10^9$ scf/yr	TSP/PM10	P	Fuel Spec. Clean burning fuel	BACT-PSD			1	0
Phoenix Power Partners	Greely, Colorado	05/11/93	Generator, Steam, With Duct Burner	50	PM10	P	Fuel Spec: Natural Gas Combustion	BACT-OTHER			20.2 tpy	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Westinghouse W501D5 Turbines	1400	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.05% by weight	BACT-OTHER	0.007		7.2	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Duct Burners	214.1	PM/PM10	P	Fuel Spec: Natural gas only	BACT-OTHER	0.011		2.0	0
Portside Energy Corp.	Portage, Indiana	05/13/96	Turbine, Natural Gas-Fired	63 MW	PM/PM10	N	None	BACT-PSD			5.0	0
Saguaro Power Company	Henderson, Nevada	06/17/91	2 GE F-6 Turbines	34.5 MW	PM	A	Combustion System	LAER			2.5	0
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two GE Frame 7EA Model Turbines	1123	PM/PM10	P	Combustion controls	BACT-OTHER	0.0062			0
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two Duct Burners	553	PM/PM10	P	Combustion controls	BACT-OTHER	0.003			0
Savannah Electric and Power Co.	Effingham, Georgia	02/12/92	Turbines, 8	1032	PM	P	Fuel Spec: Low sulfur fuel	BACT-PSD	0.006			0
SC Electric and Gas Company - Hagood Station	Charleston, South Carolina	12/11/89	Internal Combustion Turbine	110 MW	PM	P	Fuel Spec: Low ash fuel	BACT-PSD			45	0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Combustion Turbines (2)	1173	PM/PM10	P	Combustion controls and fuel spec: Low sulfur oil	BACT-OTHER	0.004			0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Duct Burners (2)	206	PM/PM10	P	Combustion controls and fuel spec: Low sulfur oil	BACT-OTHER	0.014			0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Combustion Turbine (79 MW) (modified existing source)	79 MW	PM/PM10	P	Combustion controls and fuel spec: Low sulfur oil	BACT-OTHER	0.004			0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Duct Burners (modified existing source)	123	PM/PM10	P	Combustion controls and fuel spec. Low sulfur oil	BACT-OTHER	0.014			0
Seminole Hardee Unit 3	Fort Green, Florida	01/01/96	Combined Cycle Combustion Turbine	140 MW	PM/PM10	P	Dry Low NO_x Burner, Good Combustion, Fuel Spec: Low S Oil	BACT-PSD			7	0
South Mississippi Electric Power Assoc.	Mosell, Mississippi	04/09/96	Combustion Turbine, Combined Cycle	1299	PM	P	Good Combustion Controls	BACT-PSD			8.1	0

TABLE 5-8
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - PM/PM10 CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(gr/dscf)	(lb/hr)	CONTROL EFFICIENCY
TBG Cogen Cogeneration Plant	Bethpage, New York	08/05/90	GE LM 2500 Gas Turbine	214.9	PM/PM10	P	Fuel Spec: Sulfur content not to exceed 0.037% by weight	BACT-OTHER	0.024		5.0	0
TBG Cogen Cogeneration Plant	Bethpage, New York	08/05/90	Cogen Duct Burner[c]	161.8	PM/PM10	P	Fuel Spec: Natural gas only	BACT-OTHER	0.02		7.5	0
Thermo Industries, LTD.	Ft. Lupton, Colorado	02/19/92	Turbines, Gas Fired, 5 Each (Each with duct burner @ 240 MMBtu/hr)	246	PM/PM10	P	Fuel Spec: Natural gas only	OTHER			25.8	0
Tiger Bay LP	Ft Meade, Florida	05/17/93	Turbine, Gas	1614.8	PM/PM10	P	Good combustion practices	BACT-PSD	0.0056		9.0	0
Tiger Bay LP	Ft Meade, Florida	05/17/93	Duct Burner, Gas	100	PM/PM10	P	Good combustion practices	BACT-PSD	0.01			0
Trigen Mitchel Field	Hempstead, New York	04/16/93	GE Frame 6 Gas Turbine	424.7	PM/PM10	N	No controls	BACT-OTHER	0.006		2.9	0
Trigen Mitchel Field	Hempstead, New York	04/16/93	Duct Burner	195.3	PM/PM10	N	No control	BACT-OTHER	0.015		2	0
SC Electric and Gas Company - Hagood Station	Charleston, South Carolina	12/11/89	Internal Combustion Turbine	110 MW	PM	P	Fuel Spec: Low ash fuel	BACT-PSD			45	0
WEPCU, Paris Site	Paris, Wisconsin	08/29/92	Turbines, Combustion (4)	Unknown	PM	P	Good Combustion	BACT-PSD			12	0
West Campus Cogeneration Company	College Station, Texas	05/02/94	2 Gas Turbines [Information represents the 2 turbines combined]	75.3 MW	PM10	P	Internal Combustion Controls	BACT-PSD			52 tpy	0

[a] Rated heat input for *each* combustion unit unless otherwise noted.

[b] RBLC Control Method Codes are as follows:
- A = Add-on control equipment
- N = No feasible controls
- P = Pollution prevention techniques, e.g., any required process modification, change in raw material, or management practice designed to decrease or prevent emissions.
- ND = No determination was made.

[c] The PM/PM10 emission limit of 0.02 lb/MMBtu shall be enforced when the gas turbine and the duct burner are firing simultaneously.

NOTE: The PM/PM10 emission limit for this facility is the combined emissions for the gas turbine and duct burner while firing natural gas. The emission limit is 0.028 lb/MMBtu and 12 lb/hr

TABLE 5-9
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - CO CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT			CONTROL EFFICIENCY
									(lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	
Algonquin Gas Transmission Co.	Burrillville, Rhode Island	07/31/91	Turbine, Gas (2)	49	CO	P	Cood Combustion Practices	BACT-OTHER	0.114			0
Anitec Cogen Plant	Binghamton, New York	07/07/93	GE LM5000 Combined Cycle Gas Turbine EP#00001	451	CO	P	Baffle Chamber	BACT-OTHER			33 (<46°F) 24 (>46°F)	80
Anitec Cogen Plant	Binghamton, New York	07/07/93	Duct Burner EP#00001	70	CO	N	No Controls	BACT-OTHER	0.035		2.5	0
Auburndale Power Partners, LP	Auburndale, Florida	12/14/92	Turbine, Gas	1214	CO	P	Good combustion practices	BACT-PSD		15	43.5	0
Baltimore Gas & Electric	Perryman, Maryland	03/24/95	Turbine, 140 MW Natural Gas Fired Electric	140 MW	CO	P	Good combustion practices	BACT-PSD		20		0
Bear Island Paper Company, L P.	Ashland, Virginia	10/30/92	Turbine, Combustion Gas	474	CO	P	Good Combustion	BACT-PSD			11.0	0
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Duct Burner	129	CO	P	Good Combustion	BACT-PSD			19 0	0
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Turbine, Combustion	1175	CO	P	Furnace Design	BACT-PSD			62	91
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Burner, Duct	197	CO	P	Furnace Design	BACT-PSD			15.8	91
Blue Mountain Power, LP	Richland, Pennsylvania	07/31/96	Combustion Turbine with Heat Recovery Boiler	153 MW	CO	A	Oxidation Catalyst	OTHER		3.1		80
Brooklyn Navy Yard Cogeneration Partners L.P.	New York, New York	06/06/95	Turbine, Natural Gas Fired	240 MW	CO	N	None	LAER		4	11	0
Buchnell University	Lewisburg, Pennsylvania	11/26/97	N. G. Gas Fired Solar Taurus Turbine	5 MW	CO	P	Good Comb. Practices	BACT-PSD		50		0
Carolina Power & Light	Goldsboro, North Carolina	04/11/96	4 GE PG7231 FA Simple Cycle Turbines	1907 6	CO	P	Combustion Control	BACT-PSD	0.042		80.0	0
Carolina Power and Light	Darlington, South Carolina	08/31/94	Stationary Gas Turbine	1520	CO	P	Proper operation to achieve good combustion	BACT-PSD			702 0	0
Carolina Power and Light Co.	Darlington, South Carolina	09/23/91	Turbine, I.C.	80 MW	CO	N	No control	BACT-PSD			60.0	0
Charles Larsen Power Plant	Lakeland, Florida	07/25/91	Turbine, Gas, 1 Each	80 MW	CO	P	Combustion Control	BACT-PSD		25		0
Cimarron Chemical	Johnstown, Colorado	03/25/91	Turbine #2, GE Frame 6	33 MW	CO	P	CO Catalyst	OTHER			<250 tpy	0
CNG Transmission	Washington Court House, Ohio	08/12/92	Turbine, Natural Gas (3)	5500 HP	CO	P	Fuel Spec: Use of natural gas	OTHER	0.015 g/hp-hr			0

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COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
Colorado Power Partnership	Brush, Colorado	05/01/92	Two Natural gas turbines	385	CO	N	No controls	BACT-PSD		22.4		0
CSW Nevada, Inc.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	CO	P	Fuel Spec: Natural Gas	BACT-PSD			83.0	0
Duke Power Co. Lincoln Combustion Turbine Station	Lowesville, North Carolina	12/20/91	Turbine, Combustion	1313	CO	P	Combustion Control	BACT-PSD			59.0	0
East Kentucky Power Cooperative	Clark, Kentucky	03/24/93	Turbines (5), #2 Fuel Oil and Natural Gas	1492	CO	P	Proper Combustion Techniques	BACT-OTHER			75.0	0
El Paso Natural Gas	Arizona	10/25/91	Turbine, Gas, Solar Centaur H	5500 HP	CO	P	Lean Burn	BACT-PSD		10.5		0
El Paso Natural Gas	Arizona	10/18/91	Turbine, Nat. Gas Transm., GE Frame 3	12000 HP	CO	P	Lean Burn	BACT-PSD		10.5		0
Enron Louisiana Energy Company	Eunice, Louisiana	08/05/91	Turbine, Gas, 2	39.1	CO	N	No controls	BACT-PSD		60	5.8	0
Florida Gas Transmission Company	Mobile, Alabama	08/05/93	Turbine, Natural Gas	12600 BHP	CO	P	Dry Combustion Controls	BACT-PSD	0.42 g/hp-hr			0
Florida Power and Light	Lavogrome Repowering Station, Florida	03/14/91	Turbines, Gas, 4 Each	240 MW	CO	P	Combustion Control	BACT-PSD		30		0
Florida Power and Light	N. Palm Beach, Florida	06/05/91	Turbines, Gas, 4 Each	400 MW	CO	P	Combustion Control	BACT-PSD		30		0
Florida Power Corporation Polk County Site	Bartow, Florida	02/25/94	Turbine, Natural Gas (2)	1510	CO	P	Good Combustion Practices	BACT-PSD		25	77	0
Formosa Plastics Corporation, Baton Rouge Plant	Baton Rouge, Louisiana	03/07/97	Turbine/HRSG, Gas Cogeneration	450	CO	P	Combustion Design and Construction	BACT-PSD			70	0
Formosa Plastics Corporation, LA	Baton Rouge, Louisiana	03/02/95	Turbine/HRSG, Gas Cogeneration	450	CO	P	Proper Operation	BACT-PSD			25.8	0
Fulton Cogen Plant	Fulton, New York	09/15/94	GE LM500 Turbine	500	CO	N	None	BACT-OTHER		107	120	0
Georgia Power Company, Robins Turbine Project	Robins Air Force Base, Georgia	05/13/94	Turbine, Combustion, Natural Gas	80 MW	CO	P	Fuel Spec: Low sulfur fuel	BACT-PSD		56		0
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbine, Facility	1331.13x10^7 scf/yr	CO	P	Good Combustion Practices	BACT-PSD	0.0377		249.9 tpy	0

TABLE 5-9
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - CO CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbines (2) [Each with a duct burner]	1.51×10^{9} scf/yr	CO	P	Good Combustion Practices	BACT-PSD	0.0377		57	0
Grays Ferry Co. Generation Partnership	Philadelphia, Pennsylvania	11/04/92	Turbine (Natural Gas & Oil) [Emission limits are total for entire facility]	1150	CO	P	Combustion	BACT-OTHER	0.0055			0
Hartwell Energy Limited Partnership	Hartwell, Georgia	07/28/92	Turbine, Gas Fired (2 Each)	1817	CO	P	Fuel Spec: Clean burning fuels	BACT-PSD		25		0
Hermiston Generating Co.	Hermiston, Oregon	04/01/94	Turbines, Natural Gas (2)	1696	CO	P	Good Combustion Practices	BACT-PSD		15		0
Indeck Energy Company	Silver Springs, New York	05/12/93	GE Frame 6 Gas Turbine	491	CO	N	No Controls	BACT		40		0
Indeck Energy Company	Silver Springs, New York	05/12/93	Duct Burner EP#00001	100	CO	N	No Controls	BACT-OTHER	0.14		12.0	0
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	GE Frame 6 Gas Turbine	533	CO	N	No Controls	BACT-OTHER		10	10.0	0
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	Duct Burner	30	CO	N	No Controls	BACT-OTHER	0.128		3.84	0
Indeck-Yerkes Energy Services	Tonawanda, New York	06/24/92	GE Frame 6 Gas Turbine (EP#00001)	432.2	CO	N	No Controls	BACT-OTHER		10	10.0	0
Indeck-Yerkes Energy Services	Tonawanda, New York	06/24/92	Duct Burner	20	CO	N	No Controls	BACT-OTHER	0.04		0.8	0
International Paper	Mansfield, Louisiana	02/24/94	Turbine/HRSG, Gas Cogen	338	CO	P	Combustion Control	BACT			165.9	0
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Turbine, Stationary (Gas-Fired)	40 MW	CO	P	Design	BACT-PSD			22.1	0
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Duct Burners	Unknown	CO	P	Design	BACT-PSD			42.2	0
Kalamazoo Power Limited	Comstock, Michigan	12/03/91	Turbine, Gas Fired, 2, w/ Waste Heat Boilers	1805.9	CO	P	Dry Low NOx Burners	BACT-PSD		20		0
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	GE Frame 6 Gas Turbine	498	CO	N	No controls	BACT-OTHER		9	11	0
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	Duct Burner	44	CO	N	No controls	BACT-OTHER		22	28.3	Emission rates represent GT and DB combined
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Turbine, Combustion	650	CO	P	Combustion Controls	BACT-OTHER		9.5		0
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Duct Burner	90	CO	P	Combustion Control	BACT-OTHER	0.15			0

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SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - CO CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
Kamine/Besicorp Carthage L.P	Carthage, New York	01/18/94	GE Frame 6 Gas Turbine	491	CO	N	None	BACT-OTHER		10	11	0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	GE Frame 6 Gas Turbine	500	CO	N	No controls	BACT-OTHER	0.02		10	0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	Duct Burner	90	CO	N	No controls	BACT-OTHER	0.16		14.4	0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Siemens V64.3 Gas Turbine (EP#00001)	650	CO	N	No Controls	BACT-OTHER		9.5		0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Duct Burner (EP#00001)	90	CO	N	No Controls	BACT-OTHER	0.15			0
Kentucky Utilities Company	Mercer, Kentucky	03/10/92	Turbine, #2 Fuel Oil/Natural Gas (8)	1500	CO	P	Combustion Control	BACT-PSD			75	0
Key West City Electric System	Key West, Florida	09/28/95	Turbine	23 MW	CO	P	Good Combustion	BACT-OTHER		20		0
Kissimmee Utility Authority	Intercession City, Florida	04/07/93	Turbine, Natural Gas	869	CO	P	Good Combustion Practices	BACT-PSD			54	0
Kissimmee Utility Authority	Intercession City, Florida	04/07/93	Turbine, Natural Gas	367	CO	P	Good Combustion Practices	BACT-PSD			40	0
Lake Cogen Limited	Umatilla, Florida	11/20/91	Turbine, Gas, 2 Each	42 MW	CO	P	Combustion Control	BACT-PSD		42		0
Lake Cogen Limited	Umatilla, Florida	11/20/91	Duct Burner, Gas	150	CO	N	Not Required	BACT-PSD	0.2			0
Lakewood Cogeneration, L.P.	Lakewood Township, New Jersey	04/01/91	Turbines (Natural Gas) (2)	1190	CO	P	Turbine Design	BACT-OTHER	0.026			0
Lederle Laboratories	Pearl River, New York	09/15/94	(2) Gas Turbines (EP #S 00101&102)	110	CO	N	No Controls	BACT-OTHER		48	12.6	0
Lederle Laboratories	Pearl River, New York	09/15/94	(2) Duct Burners (EP #S 00101&102)	99	CO	N	No controls	BACT-OTHER	0.06		5.9	0
Lilco Shoreham	Hicksville, New York	05/10/93	(3) GE Frame 7 Turbines (EP #S 00007-9)	850	CO	N	No Controls	BACT-OTHER	0.024	10	19.7	0
Lockport Cogen Facility	Lockport, New York	07/14/93	Six GE Frame 6 Turbines	423.9	CO	N	No Controls	BACT		10		0
Lockport Cogen Facility	Lockport, New York	07/14/93	Three Duct Burners	94.1	CO	N	No Controls	BACT-OTHER	0.1		9.4	0
Lordsburg L. P.	Lordsburg New Mexico	06/18/97	N. G. Turbine	100 MW	CO	P	Dry Low NOx	BACT-PSD			27	0
Marathon Oil Co. - Indian Basin N.G. Plant	Carlsbad, New Mexico	01/11/95	Turbines, Natural Gas (2)	5500 hp	CO	P	Dry low NO_x combustor	BACT-PSD			13.2	66
Mead Coated Board, Inc.	Phenix City, Alabama	03/12/97	Turbine and Duct Burners (Combined)	568	CO	P	Proper Design and Good Combustion Practices	BACT-PSD		28		0

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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
Megan-Racine Associates, Inc.	Canton, New York	08/05/89	GE LM5000-N Combined Cycle Gas Turbine	401	CO	N	No Controls	BACT-OTHER	0.026		11	0
Mid-Georgia Cogen.	Kathleen, Georgia	04/03/96	Combustion Turbine (2), Natural Gas	116 MW	CO	P	Complete Combustion	BACT-PSD		10		0
Milagro, Williams Field Service	Bloomfield, New Mexico	09/22/94	Turbine/Cogen, Natural Gas (2)	900 MMcf/day	CO	N	None	BACT-PSD		27.6		0
Muddy River L.P.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	CO	P	Fuel Spec: Natural Gas	BACT-PSD			77	0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	CO	N	No controls	BACT-PSD		11		0
Narragansett Electric/New England Power Co	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	CO	N	No controls	BACT-PSD		12		0
Nevada Power Company, Harry Allen Peaking Plant	Las Vegas, Nevada	09/18/92	Combustion Turbine Electric Power Generation (8)	75 MW	CO	P	Precision Control for the Low NO_x Combustor	BACT-PSD			32.7 tpy	0
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	11/01/90	Turbine	585	CO	A	Catalytic Oxidation	BACT-PSD	0.0055			80
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	06/09/93	Two Westinghouse CW251/B-12 Combustion Turbines	617	CO	A	Oxidation Catalyst	OTHER	0.004			0
Northern Consolidated Power	North East, Pennsylvania	05/03/91	Turbines, Gas, 2	34.6 KW	CO	A	Oxidation Catalyst	OTHER			110 tpy	90
Northern States Power Company	Sioux Falls, South Dakota	09/02/92	Turbine Simple Cycle, 4 Each	129 MW	CO	P	Good Combustion Techniques	BACT-PSD		50		0
Northwest Pipeline Corporation	La Plata "B" Station, Colorado	05/29/92	Burners, Duct, Coen	29	CO	N	No Controls	OTHER			4	0
Orange Cogeneration LP	Bartow, Florida	12/30/93	Turbine, Natural Gas, 2	368.3	CO	P	Good Combustion	BACT-PSD		30		0
Orlando Utilities Commission	Titusville, Florida	11/05/91	Turbine, Gas, 4 Each	35 MW	CO	P	Combustion control	BACT-PSD		10		0
Panda-Kathleen, L.P.	Lakeland, Florida	06/01/95	Combined Cycle Combustion Turbine	75 MW	CO	P	Combustion Controls	BACT-PSD		25		0

TABLE 5-9
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - CO CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
PASNY/Holtsville Combined Cycle Plant	Holtsville, New York	09/01/92	Turbine, Combustion Gas	1146/ 1291	CO	P	Combustion Control	BACT-OTHER		8.5		0
Patowmack Power Partners, Limited Partnership	Leesburg, Virginia	09/15/93	Turbine, Combustion, Siemens Model V84.2, 3	10.2×10^9 scf/yr	CO	P	Good Combustion Operating Practices	BACT-PSD			26	0
Peabody Municipal Light Plant	Peabody, Massachusetts	11/30/89	Turbine, Natural Gas-Fired	412	CO	P	Good Combustion Practices	BACT-OTHER		40		0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Westinghouse W501D5 Turbines	1400	CO	N	No Controls	BACT-OTHER		10	29.0	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Duct Burners	214.1	CO	N	No Controls	BACT-OTHER	0.108		17.5	0
Portland General Electric Company	Boardman, Oregon	05/31/94	Turbines	1720	CO	P	Good Combustion Practices	BACT-PSD		15		0
Portside Energy Corp.	Portage, Indiana	05/13/96	Turbine, Natural Gas-Fired	63 MW	CO	P	Good Combustion	BACT-PSD		40	40.0	0
Project Orange Associates	Syracuse, New York	12/01/93	GE LM-5000 Gas Turbine	550	CO	N	No Controls	BACT-OTHER			92 (> 20°F) 193 (<=20°F)	0
Saguaro Power Company	Henderson, Nevada	06/17/91	2 GE F-6 Turbines	34.5 MW	CO	A	Catalytic Converter	BACT-PSD			9	90
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two GE Frame 7EA Model Turbines	1123	CO	P	Oxidation Catalyst	BACT-OTHER		3		0
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two Duct Burners	553	CO	P	Oxidation Catalyst	BACT-OTHER	0.06			0
Savannah Electric and Power Co.	Effingham, Georgia	02/12/92	Turbines, 8	1032	CO	P	Fuel Spec: Low sulfur fuel	BACT-PSD		9		0
SC Electric and Gas Company - Hagood Station	Charleston, South Carolina	12/11/89	Internal Combustion Turbine	110 MW	CO	P	Good Combustion Practices	BACT-PSD			23	0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Combustion Turbines (2)	1173	CO	P	Combustion Controls	BACT-OTHER		10		0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Duct Burners (2)	206	CO	P	Combustion Controls	BACT-OTHER	0.073			0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Combustion Turbine (79 MW) (modified existing source)	1173	CO	P	Combustion Controls	BACT-OTHER		25		0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Duct Burners (modified existing source)	123	CO	P	Combustion Controls	BACT-OTHER	0.072			0
Seminole Hardee Unit 3	Fort Green, Florida	01/01/96	Combined Cycle Combustion Turbine	140 MW	CO	P	Dry Low NO_x Burner, Good Combustion Practices	BACT-PSD		20		0
Sithe/Independence Power Partners	Oswego, New York	11/24/92	4 GE Frame 7F Turbines	2133	CO	P	Combustion Controls	BACT-OTHER		13		0
South Mississippi Electric Power Assoc.	Mosell, Mississippi	04/09/96	Combustion Turbine, Combined Cycle	1299	CO	P	Good Combustion Controls	BACT-PSD		26.3		0

TABLE 5-9
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - CO CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT			CONTROL EFFICIENCY
									(lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	
Southern California Gas	Wheeler Ridge, California	10/29/91	Turbines, Gas-fired	47.64	CO	A	Oxidation Catalyst	BACT-PSD		7.74	1.13	80
Sumas Energy Inc.	Sumas, Washington	06/25/91	Turbine, Natural Gas	88 MW	CO	P	CO Catalyst	BACT-PSD		6		80
TBG Cogeneration Plant	Bethpage, New York	08/05/90	GE LM 2500 Gas Turbine	214.9	CO	P	Catalytic Oxidizer	BACT	0.181			80
TBG Cogeneration Plant	Bethpage, New York	08/05/90	Coen Duct Burner	161.8	CO	NO INFORMATION PROVIDED FOR CO						
Thermo Industries, LTD.	Ft. Lupton, Colorado	02/19/92	Turbines, Gas Fired, 5 Each (Each with duct burner @ 240 MMBtu/hr)	246	CO	P	Combustion Control	BACT-PSD		25	147.7	0
Tiger Bay LP	Ft Meade, Florida	05/17/93	Turbine, Gas	1614.8	CO	P	Good Combustion Practices	BACT-PSD	0.0303		49	0
Tiger Bay LP	Ft Meade, Florida	05/17/93	Duct Burner, Gas	100	CO	P	Good Combustion Practices	BACT-PSD	0.1		10	0
Trigen Mitchel Field	Hempstead, New York	04/16/93	GE Frame 6 Gas Turbine	424.7	CO	N	No controls	BACT-OTHER	-	10	10	0
Trigen Mitchel Field	Hempstead, New York	04/16/93	Duct Burner	195.3	CO	N	No control	BACT-OTHER	0.07		11.4	0
Unocal	Wilmington, California	07/18/89	Westinghouse Model CW251B10 Gas Turbine	Unknown	CO	A	Oxidation Catalyst	BACT-OTHER		10		75
WEPCU, Paris Site	Paris, Wisconsin	08/29/92	Turbines, Combustion (4)	Unknown	CO	N	No conrols	BACT-PSD			25	0
West Campus Cogeneration Company	College Station, Texas	05/02/94	2 Gas Turbines [Information represents the 2 turbines combined]	75.3 MW	CO	P	Internal Combustion Controls	BACT-PSD			300 tpy	0
Williams Field Services Co. - El Cedro Compressor	Blanco, New Mexico	10/29/93	Turbine, Gas Fired	11257 hp	CO	P	Combustion Control	BACT-PSD		50		0

[a] Rated heat input for *each* combustion unit unless otherwise noted.

[b] RBLC Control Method Codes are as follows:

A = Add-on control equipment
B = Both pollution prevention and add-on equipment
N = No feasible controls
P = Pollution prevention techniques, e.g., any required process modification, change in raw material, or management practice designed to decrease or prevent emissions
ND = No determination was made.

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TABLE 5-10
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - NO_x CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Algonquin Gas Transmission Co.	Burrillville, Rhode Island	07/31/91	Turbine, Gas (2)	49	NO_x	P	Low NO_x combustion	BACT-OTHER		25		0
Anitec Cogen Plant	Binghamton, New York	07/07/93	GE LM5000 Combined Cycle Gas Turbine EP#00001	451	NO_x	N	No controls	BACT-OTHER		25	41.0	0
Anitec Cogen Plant	Binghamton, New York	07/07/93	Duct Burner EP#00001	70	NO_x	P	Zink Low NO_x Duct Burner	BACT-OTHER	0.1		7.0	30
Auburndale Power Partners, LP	Auburndale, Florida	12/14/92	Turbine, Gas	1214	NO_x	P	Dry low NO_x combustor	BACT-PSD		15		0
Baltimore Gas & Electric	Perryman, Maryland	03/24/95	Turbine, 140 MW Natural Gas Fired Electric	140 MW	NO_x	P	Dry low NO_x Burners	BACT-PSD	0.04	15		91
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Turbine, Combustion Gas	474	NO_x	A	SCR	BACT-PSD		9	11.8	74.5
Bear Island Paper Company, L.P.	Ashland, Virginia	10/30/92	Duct Burner	129	NO_x	A	SCR	BACT-PSD		9	3.2	74.5
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Turbine, Combustion	1175	NO_x	B	SCR, Steam Injection	BACT-PSD		9		91
Bermuda Hundred Energy Limited Partnership	Chesterfield, Virginia	03/03/92	Burner, Duct	197	NO_x	B	SCR, Steam Injection	BACT-PSD		9		91
Blue Mountain Power, LP	Richland, Pennsylvania	07/31/96	Combustion Turbine with Heat Recovery Boiler	153 MW	NO_x	B	Dry low NO_x burner with SCR; water injection when firing oil	LAER		4	23.3	84
Brooklyn Navy Yard Cogeneration Partners L.P.	New York, New York	06/06/95	Turbine, Natural Gas Fired	240 MW	NO_x	A	SCR	LAER		3.5	16	0
Brush Cogeneration Partnership	Brush, Colorado	05/01/94	Turbine	350	NO_x	P	Dry Low NO_x Burner	BACT-PSD		25		74
Bucknell University	Lewisburg, PA	11/26/97	N. G. Fired Solar Taurus Turbine	% MW	NO_x	P	Low NOx Burner	BACT-OTHER		25		0
"	"	"	Heat Recovery Boiler	24,000 lb/hr steam	"	N	None	"	0.01			0
Carolina Power & Light	Goldsboro, North Carolina	04/11/96	4 GE PG7231 FA Simple Cycle Turbines	1907.6	NO_x	P	Water Injection	BACT-PSD	0.084	25	158.0	0
Carolina Power and Light	Darlington, South Carolina	08/31/94	Stationary Gas Turbine	1520	NO_x	P	Water Injection	BACT-PSD		25	140.0	30
Carolina Power and Light Co.	Darlington, South Carolina	09/23/91	Turbine, I.C.	80 MW	NO_x	P	Water Injection	BACT-PSD			292.0	50
Charles Larsen Power Plant	Lakeland, Florida	07/25/91	Turbine, Gas, 1 Each	80 MW	NO_x	P	Water injection	BACT-PSD		25		0
Cimarron Chemical	Johnstown, Colorado	03/25/91	Turbine #1, GE Frame 6	33 MW	NO_x	P	Water injection	OTHER		25		0

TABLE 5-10
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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Cimarron Chemical	Johnstown, Colorado	03/25/91	Turbine #2, GE Frame 6	33 MW	NO_x	P	SCR	OTHER		9		0
CNG Transmission	Washington Court House, Ohio	08/12/92	Turbine, Natural Gas (3)	5500 HP	NO_x	P	Low NO_x Combustor	BACT-OTHER		42		0
Colorado Power Partnership	Brush, Colorado	05/01/92	Two Natural gas turbines	385	NO_x	P	Water Injection	BACT-PSD		42		66
Connecticut Light and Power[c]	Connecticut	Last three to five years	Turbine, Combustion	408	NO_x	P	Water Injection	Unknown			24.9 tpy	Unknown
CSW Nevada, Inc.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	NO_x	P	Dry Low NO_x Combustor	BACT-PSD			273.0	0
Duke Power Co Lincoln Combustion Turbine Station	Lowesville, North Carolina	12/20/91	Turbine, Combustion	1313	NO_x	B	Water Injection	BACT-PSD		25	119.0	0
East Kentucky Power Cooperative	Clark, Kentucky	03/24/93	Turbines (5), #2 Fuel Oil and Natural Gas	1492	NO_x	P	Water Injection	BACT-OTHER		25		46
El Paso Natural Gas	Arizona	10/25/91	Turbine, Gas, Solar Centaur H	5500 HP	NO_x	P	Dry Low NO_x Combustor	BACT-PSD		42		51
El Paso Natural Gas	Arizona	10/18/91	Turbine, Nat. Gas Transm., GE Frame 3	12000 HP	NO_x	P	Dry Low NO_x Combustor	BACT-PSD		42		80
Enron Louisiana Energy Company	Eunice, Louisiana	08/05/91	Turbine, Gas, 2	39.1	NO_x	P	Water Injection	BACT-PSD		40	6.3	71
Fleetwood Cogeneration Associates	Fleetwood, Pennsylvania	04/22/94	GE LM6000 Turbine with Waste Heat Boiler	360	NO_x	B	SCR with Dry Low NO_x Combustors	BACT-OTHER		15	21	47
Florida Gas Transmission Company	Mobile, Alabama	08/05/93	Turbine, Natural Gas	12600 BHP	NO_x	P	Dry Low NO_x Combustion	BACT-PSD	0.58 g/hp-hr			71
Florida Gas Transmission Company	Perry, Florida	09/27/93	Turbine, Gas	131.59	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		25		0
Florida Power and Light	Lavogrome Repowering Station, Florida	03/14/91	Turbines, Gas, 4 Each	240 MW	NO_x	P	Combustion Control	BACT-PSD		42		0
Florida Power and Light	N. Palm Beach, Florida	06/05/91	Turbines, Gas, 4 Each	400 MW	NO_x	P	Low NO_x Combustors	BACT-PSD		25		0

TABLE 5-10
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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Florida Power Corporation Polk County Site	Bartow, Florida	02/25/94	Turbine, Natural Gas (2)	1510	NO_x	P	Low NO_x Combustor	BACT-PSD		12	73	0
Formosa Plastics Corporation, Baton Rouge Plant	Baton Rouge, Louisiana	03/07/97	Turbine/HRSG, Gas Cogeneration	450	NO_x	P	Dry Low NO_x Burners/ Combustion Design and Control	LAER		9	75	0
Formosa Plastics Corporation, LA	Baton Rouge, Louisiana	03/02/95	Turbine/HRSG, Gas Cogeneration	450	NO_x	P	Dry Low NO_x Burners/ Combustion Design and Control	LAER		9	24.8	0
Fulton Cogen Plant	Fulton, New York	09/15/94	GE LM500 Turbine	500	NO_x	P	Water Injection	BACT		36	65	58.5
Gainsville Regional Utilities	Gainsville, Florida	04/11/95	Simple Cycle Combustion Turbine, Gas/No. 2 Oil Back-up	74 MW	NO_x	P	Low NO_x Burners	BACT-PSD		15	58	0
Georgia Gulf Corporation	Plaquemine, Louisiana	03/26/96	Generator, Natural Gas-Fired Turbine	1123	NO_x	P	Steam Injection	BACT-PSD		25		0
Georgia Power Company, Robins Turbine Project	Robins Air Force Base, Georgia	05/13/94	Turbine, Combustion, Natural Gas	80 MW	NO_x	P	Water Injection, Fuel Spec: Natural Gas	BACT-PSD		25		0
Goal Line, LP Icefloe	Escondido, California	11/03/92	GE LM6000 Turbine	386	NO_x	B	SCR, Water Injection	BACT-OTHER	0.02	5		88
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbine, Facility	1331.13×10^7 scf/yr	NO_x	B	SCR with Water Injection	BACT-PSD	0.033	9		80
Gordonsville Energy L.P.	Fairfax, Virginia	09/25/92	Turbines (2) [Each with a duct burner]	1.51×10^9 scf/yr	NO_x	B	SCR with Water Injection	BACT-PSD		9	50	80
Granite Road Limited	California	5/6/1991	GE LM5000 Turbine	460.9	NO_x	B	SCR, Steam Injection	BACT-PSD	0.0126	3.5		97
Grays Ferry Co. Generation Partnership	Philadelphia, Pennsylvania	11/04/92	Turbine (Natural Gas & Oil) [Emission limits are total for entire facility]	1150	NO_x	P	Dry Low NO_x Burner, Combustion Control	BACT-OTHER		9		0
Hartwell Energy Limited Partnership	Hartwell, Georgia	07/28/92	Turbine, Gas Fired (2 Each)	1817	NO_x	P	Water Injection	BACT-PSD		25		0
Hermiston Generating Co.	Hermiston, Oregon	04/01/94	Turbines, Natural Gas (2)	1696	NO_x	A	SCR	BACT-PSD		4.5		82
Indeck Energy Company	Silver Springs, New York	05/12/93	GE Frame 6 Gas Turbine	491	NO_x	P	Steam Injection	BACT-OTHER		32		58.2
Indeck Energy Company	Silver Springs, New York	05/12/93	Duct Burner EP#00001	100	NO_x	P	Fuel Spec: Natural gas only	NSPS	0.1		8.5	0
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	GE Frame 6 Gas Turbine	533	NO_x	P	Steam Injection	BACT-OTHER		42	75.0	53

TABLE 5-10
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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Indeck-Oswego Energy Center	Oswego, New York	10/06/94	Duct Burner	30	NO_x	P	Fuel Spec: Natural gas only	BACT-OTHER	0.117		3.51	0
Indeck-Yerkes Energy Services	Tonawanda, New York	06/24/92	GE Frame 6 Gas Turbine (EP#00001)	432.2	NO_x	P	Steam Injection	BACT-OTHER		42	74	35
Indeck-Yerkes Energy Services	Tonawanda, New York	06/24/92	Duct Burner	20	NO_x	P	Fuel Spec: Natural gas only	BACT-OTHER	0.11		2.2	0
International Paper	Mansfield, Louisiana	02/24/94	Turbine/HRSG, Gas Cogen	338	NO_x	P	Dry Low NO_x burners	BACT	0.08			0
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Turbine, Stationary (Gas-Fired)	40 MW	NO_x	P	Steam Injection	BACT-PSD	0.08			0
International Paper Co., Riverdale Mill	Selma, Alabama	01/11/93	Duct Burners	Unknown	NO_x	P	Low NO_x burners	BACT-PSD		25		0
Kalamazoo Power Limited	Comstock, Michigan	12/03/91	Turbine, Gas Fired, 2, w/ Waste Heat Boilers	1805.9	NO_x	P	Dry low NO_x burners	BACT-PSD		15		0
Kamine South Glens Falls Cogen Co	Saratoga, New York	09/10/92	GE Frame 6 Gas Turbine	498	NO_x	P	Water Injection	BACT		42	76.6	50
Kamine South Glens Falls Cogen Co.	Saratoga, New York	09/10/92	Duct Burner	44	NO_x	N	No controls	BACT-OTHER		42	87.4	Emission rates represent GT and DB combined
Kamine South Glens Falls Cogen Co	Saratoga, New York	09/10/92	GE Frame 6 Gas Turbine	498	NO_x	P	Water Injection	BACT-PSD		42	76.6	50
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Turbine, Combustion	650	NO_x	B	Dry low NO_x or SCR	BACT-OTHER		9		0
Kamine/Besicorp Beaver Falls Cogeneration Facility	Beaver Falls, New York	11/09/92	Duct Burner	90	NO_x	P	Low NO_x Burner	BACT-OTHER	0.1			0
Kamine/Besicorp Carthage L.P.	Carthage, New York	01/18/94	GE Frame 6 Gas Turbine	491	NO_x	P	Steam Injection	BACT		42	76.6	63
Kamine/Besicorp Corning L.P.	South Corning, New York	11/05/92	Turbine, Combustion	653	NO_x	B	Dry low NO_x or SCR	BACT-OTHER		9		0
Kamine/Besicorp Corning L.P	South Corning, New York	11/05/92	Burner, Duct	90	NO_x	P	Low NO_x burner	BACT-OTHER	0.1			0
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	GE Frame 6 Gas Turbine	500	NO_x	P	Steam Injection	BACT		42	80.1	35
Kamine/Besicorp Natural Dam LP	Natural Dam, New York	12/31/91	Duct Burner	90	NO_x	N	No controls	BACT-OTHER	0.1		9	0
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Siemens V64.3 Gas Turbine (EP#00001)	650	NO_x	P	Water Injection	BACT-OTHER		25		70

TABLE 5-10
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FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
Kamine/Besicorp Syracuse LP	Solvay, New York	12/10/94	Duct Burner (EP#00001)	90	NO_x	N	No controls	BACT-OTHER	0.1			0
Kentucky Utilities Company	Mercer, Kentucky	03/10/92	Turbine, #2 Fuel Oil/Natural Gas (8)	1500	NO_x	P	Water Injection	BACT-PSD		42		0
Key West City Electric System	Key West, Florida	09/28/95	Turbine	23 MW	NO_x	P	Water Injection	BACT-OTHER		75		0
Kingsburg Energy Systems	California	9/28/89, (updated 8/3/93)	GE LM2500 Gas Turbine with Duct Burner	252 (turbine) 110 (duct burner)	NO_x	B	SCR, Steam Injection	BACT-PSD		6		90
Kissimmee Utility Authority	Intercession City, Florida	04/07/93	Turbine, Natural Gas	869	NO_x	P	Dry low NO_x combustor	BACT-PSD		15		0
Kissimmee Utility Authority	Intercession City, Florida	04/07/93	Turbine, Natural Gas	367	NO_x	P	Dry low NO_x combustor	BACT-PSD		15		0
Lake Cogen Limited	Umatilla, Florida	11/20/91	Turbine, Gas, 2 Each	42 MW	NO_x	P	Combustion Control	BACT-PSD		25		0
Lake Cogen Limited	Umatilla, Florida	11/20/91	Duct Burner, Gas	150	NO_x	N	No controls	BACT-PSD	0.1			0
Lakewood Cogeneration, L.P.	Lakewood Township, New Jersey	04/01/91	Turbines (Natural Gas) (2)	1190	NO_x	B	SCR, Dry low NO_x burner	BACT-OTHER	0.033			64
Lederle Laboratories	Pearl River, New York	09/15/94	(2) Gas Turbines (EP #S 00101&102)	110	NO_x	P	Steam Injection	BACT-PSD		42	18	0
Lederle Laboratories	Pearl River, New York	09/15/94	(2) Duct Burners (EP #S 00101&102)	99	NO_x	N	No controls	BACT-OTHER	0.4		36.3	0
Linden Cogeneration Technology	Linden, New Jersey	01/21/92	Turbine, Natural Gas Fired	$50x10^{12}$ MMBtu/yr	NO_x	B	Steam Injection and SCR	BACT-PSD			33.8	94.5
Lockport Cogen Facility	Lockport, New York	07/14/93	Six GE Frame 6 Turbines	423.9	NO_x	P	Steam Injection	BACT-OTHER		42		78
Lockport Cogen Facility	Lockport, New York	07/14/93	Three Duct Burners	94.1	NO_x	P	Fuel Spec: Natural gas only	BACT-OTHER	0.2		18.8	0
Lordsburg L. P.	Lordsburg, New Mexico	06/18/97	N. G. Turbine	100 MW	NO_x	P	Dry Low NOx Burner	BACT-PSD			74.4	80
LSP-Cottage Grove, L.P.	Cottage Grove, Minnesota	03/01/95	Combustion Turbine/Generator	1970	NO_x	P	SCR	BACT-PSD		4.5		70
Marathon Oil Co. - Indian Basin N.G. Plant	Carlsbad, New Mexico	01/11/95	Turbines, Natural Gas (2)	5500 hp	NO_x	P	Dry low NO_x combustor	BACT-PSD			7.4	66
Mead Coated Board, Inc.	Phenix City, Alabama	03/12/97	Turbine and Duct Burners (Combined)	568	NO_x	P	Dry low NO_x burner	BACT-PSD		25		0

TABLE 5-10
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - NO_x CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
Megan-Racine Associates, Inc	Canton, New York	08/05/89	GE LM5000-N Combined Cycle Gas Turbine	401	NO_x	P	Water Injection	BACT-OTHER		42		60
Megan-Racine Associates, Inc.	Canton, New York	08/05/89	Duct Burner	40	NO_x	P	Fuel Spec: Natural gas only	BACT-OTHER	0.1			0
Mid-Georgia Cogen	Kathleen, Georgia	04/03/96	Combustion Turbine (2), Natural Gas	116 MW	NO_x	B	Dry low NO_x burner with SCR	BACT-PSD		9		0
Milagro, Williams Field Service	Bloomfield, New Mexico	09/22/94	Turbine/Cogen, Natural Gas (2)	900 MMcf/day	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		9		94
Muddy River L.P.	Moapa, Nevada	06/10/94	Combustion Turbine	140 MW	NO_x	P	Low NO_x Combustor	BACT-PSD			303	0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	NO_x	A	SCR	BACT-PSD		9		0
Narragansett Electric/New England Power Co.	Providence, Rhode Island	04/13/92	Turbine, Gas and Duct Burner (96 MMBtu/hr)	1360	NO_x	A	SCR	BACT-PSD		25		0
Nevada Power Company, Harry Allen Peaking Plant	Las Vegas, Nevada	09/18/92	Combustion Turbine Electric Power Generation (8)	75 MW	NO_x	P	Low NO_x Combustor	BACT-PSD			88.1 tpy	0
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	11/01/90	Turbine	585	NO_x	B	Steam Injection and SCR	BACT-PSD	0.033			94
Newark Bay Cogeneration Partnership, L.P.	Newark, New Jersey	06/09/93	Two Westinghouse CW251/B-12 Combustion Turbines	617	NO_x	A	SCR	BACT-PSD		8.3		0
Northern Consolidated Power	North East, Pennsylvania	05/03/91	Turbines, Gas, 2	34.6 KW	NO_x	B	Steam Injection/SCR in 1997	BACT-OTHER		25		85
Northern States Power Company	Sioux Falls, South Dakota	09/02/92	Turbine Simple Cycle, 4 Each	129 MW	NO_x	B	Water Injection	BACT-PSD		24		0
Northwest Pipeline Company	Sumas, Washington	08/13/92	Turbine, Gas-Fired	12100 hp	NO_x	P	Advanced Dry Low NO_x Combustor	BACT-PSD		42		76
Northwest Pipeline Corporation	La Plata "B" Station, Colorado	05/29/92	Turbine, Solar Taurus	45	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		95		0
Oklahoma Municipal Power Authority	Ponca City, Oklahoma	12/17/92	Turbine, Combustion	58 MW	NO_x	P	Combustion Controls	BACT-OTHER		25		83
Orange Cogeneration LP	Bartow, Florida	12/30/93	Turbine, Natural Gas, 2	368.3	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		15		0

TABLE 5-10
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - NO_x CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Orlando Utilities Commission	Titusville, Florida	11/05/91	Turbine, Gas, 4 Each	35 MW	NO_x	P	Wet Injection	BACT-PSD		42		70
Pacific Gas Transmission	Madras, Oregon	11/03/89	Turbine, Natural Gas	14600 hp	NO_x	P	Low NO_x Burner	BACT-PSD		42	17	75
Pacific Gas Transmission Company	Madras, Oregon	06/19/90	Turbine Gas, Compressor Station	110	NO_x	P	Low NO_x Burner Design	NSPS		199	68.5	30
Panda-Kathleen, L.P.	Lakeland, Florida	06/01/95	Combined Cycle Combustion Turbine	75 MW	NO_x	P	Dry Low NO_x Burner	BACT-PSD		15		0
PASNY/Holtsville Combined Cycle Plant	Holtsville, New York	09/01/92	Turbine, Combustion Gas	1146	NO_x	P	Dry Low NO_x Combustion	BACT-OTHER		9		0
Patowmack Power Partners, Limited Partnership	Leesburg, Virginia	09/15/93	Turbine, Combustion, Siemens Model V84.2, 3	10.2×10^9 scf/yr	NO_x	P	Dry Low NO_x Combustor; design, water injection	BACT-PSD			131	0
Peabody Municipal Light Plant	Peabody, Massachusetts	11/30/89	Turbine, Natural Gas-Fired	412	NO_x	P	Water Injection	BACT-OTHER		25		0
Pedericktown Cogeneration Limited Partnership	Oldmans Township, New Jersey	02/23/90	Turbine, Natural Gas Fired	1000	NO_x	B	Steam Injection and SCR	BACT-PSD	0.044	9		93
Pepco - Chalk Point Plant	Eagle Harbor, Maryland	06/25/90	Turbine 105 MW Natural Gas Fired Electric	105 MW	NO_x	B	Dry Premix and Water Injection	BACT-PSD		77		0
Pepco - Chalk Point Plant	Eagle Harbor, Maryland	06/25/90	Turbine 84 MW Natural Gas Fired Electric	84 MW	NO_x	P	Quiet Combustion and Water Injection	BACT-PSD		25		0
Pepco - Station A	Dickerson, Maryland	05/31/90	Turbine	124 MW	NO_x	P	Water Injection	BACT-PSD		42	321	0
Phoenix Power Partners	Greely, Colorado	05/11/93	GE LM 6000 N.G. Turbine	311	NO_x	P	Dry Low NO_x Combustion	BACT-OTHER		22	34.6	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Westinghouse W501D5 Turbines	1400	NO_x	B	Steam Injection followed by SCR	BACT-OTHER		4.5	23.6	0
Pilgrim Energy Center	Islip, New York	12/01/95	Two Duct Burners	214.1	NO_x	P	Fuel Spec: Natural gas only	BACT-OTHER	0.012			0
Portland General Electric Company	Boardman, Oregon	05/31/94	Turbines	1720	NO_x	A	SCR	BACT-PSD		4.5		82
Proctor and Gamble Paper Products Co (Charmin)	Mehoopany, Pennsylvania	05/31/95	Westinghouse W251B10 Turbine	580	NO_x	P	Steam Injection	RACT		55		75
Project Orange Associates	Syracuse, New York	12/01/93	GE LM-5000 Gas Turbine	550	NO_x	B	Steam Injection, Fuel Spec: Natural gas only	BACT-OTHER		25	47	80

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TABLE 5-10
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - NO_x CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Saguaro Power Company	Henderson, Nevada	06/17/91	2 GE F-6 Turbines	34.5 MW	NO_x	A	SCR	BACT-PSD	summer: winter:	9 11	13.5 16.9	80
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two GE Frame 7EA Model Turbines	1123	NO_x	A	SCR	BACT-OTHER		9		0
Saranac Energy Company	Plattsburgh, New York	07/31/92	Two Duct Burners	553	NO_x	A	SCR	BACT-OTHER	0.08			0
Savannah Electric and Power Co.	Effingham, Georgia	02/12/92	Turbines, 8	1032	NO_x	P	Water Injection	BACT-PSD		25		0
SC Electric and Gas Company - Hagood Station	Charleston, South Carolina	12/11/89	Internal Combustion Turbine	110 MW	NO_x	P	Water Injection	BACT-PSD			308	0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Combustion Turbines (2)	1173	NO_x	B	Steam Injection and SCR	BACT-OTHER		9		0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Duct Burners (2)	206	NO_x	B	Low NO_x Burner and SCR	BACT-OTHER	0.0181			0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Combustion Turbine (79 MW) (modified existing source)	1173	NO_x	P	Steam Injection	BACT-OTHER		25		0
Selkirk Cogeneration Partners, L.P.	Selkirk, New York	06/18/92	Duct Burners (modified existing source)	123	NO_x	P	Low NO_x Burner	BACT-OTHER	0.091			0
Seminole Fertilizer Corporation	Bartow, Florida	03/17/91	Turbine, Gas	26 MW	NO_x	A	SCR	BACT-PSD		9		0
Seminole Hardee Unit 3	Fort Green, Florida	01/01/96	Combined Cycle Combustion Turbine	140 MW	NO_x	P	Dry Low NO_x Burner, Staged Combustion	BACT-PSD		15		0
Sithe/Independence Power Partners	Oswego, New York	11/24/92	4 GE Frame 7F Turbines	2133	NO_x	B	Dry low NO_x burner with SCR	BACT-OTHER		4.5		0
Southern California Gas	Wheeler Ridge, California	10/29/91	Turbines, Gas-fired Solar Model H	47.64	NO_x	A	SCR	BACT-PSD		8	1.92	93
Southern Maryland Electric Cooperative (SMECO)	Eagle Harbor, Maryland	10/01/89	Turbine, Natural Gas Fired Electric	90 MW	NO_x	P	Water Injection	BACT-PSD		42	199	0
Southern Natural Gas Co - Selma Compressor Station	Dallas, Alabama	12/04/96	GE MS3002G Turbine	Unknown	NO_x	N	None	BACT-PSD		110	53	0
Southern Natural Gas Company	Bay Springs, Mississippi	12/17/96	Turbine, Natural Gas-Fired	9160 hp	NO_x	P	Proper Design and Operation	BACT-PSD		110	53	0
Southwestern Public Service Co./Cunningham Station	Hobbs, New Nexico	11/04/96	Combustion Turbine	100 MW	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		15		0
Southwestern Public Service Co./Cunningham Station	Hobbs, New Nexico	02/15/97	Combustion Turbine	100 MW	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		15		0

TABLE 5-10
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - NO_x CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	EMISSION LIMIT (ppm @ 15% O_2)	EMISSION LIMIT (lb/hr)	CONTROL EFFICIENCY
Sumas Energy Inc.	Sumas, Washington	06/25/91	Turbine, Natural Gas	88 MW	NO_x	A	SCR	BACT-PSD		6		90
TBG Cogeneration Plant	Bethpage, New York	08/05/90	GE LM 2500 Gas Turbine	214.9	NO_x	P	Water Injection	BACT-OTHER		75		60
TBG Cogeneration Plant	Bethpage, New York	08/05/90	Coen Duct Burner	161.8	NO_x	P	Fuel Spec: Natural gas only	BACT-OTHER	0.2			0
Thermo Industries, LTD.	Ft. Lupton, Colorado	02/19/92	Turbines, Gas Fired, 5 Each (Each with duct burner @ 240 MMBtu/hr)	246	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		25	242.4	0
Tiger Bay LP	Ft Meade, Florida	05/17/93	Turbine, Gas	1614.8	NO_x	P	Dry Low NO_x Combustion	BACT-PSD		15		0
Tiger Bay LP	Ft Meade, Florida	05/17/93	Duct Burner, Gas	100	NO_x	P	Good Combustion Practices	BACT-PSD	0.1			0
Trigen Mitchel Field	Hempstead, New York	04/16/93	GE Frame 6 Gas Turbine	424.7	NO_x	P	Steam Injection	BACT		60	90	20
Trigen Mitchel Field	Hempstead, New York	04/16/93	Duct Burner	195.3	NO_x	N	No control	BACT-OTHER	0.2		16.2	0
Unknown[c]	California Bay Area	Last three to five years	Turbine, Combustion	470	NO_x	P	Steam Injection and SCR	Unknown		5		Unknown
Unknown[c]	California Bay Area	Last three to five years	Turbine, Combustion	470	NO_x	P	Steam Injection and SCR	Unknown		5		Unknown

TABLE 5-10
SANTA ROSA ENERGY CENTER
SUMMARY OF RACT/BACT/LAER CLEARINGHOUSE (RBLC) - NO_x CONTROL TECHNOLOGIES
FOR NATURAL GAS FIRED TURBINES AND DUCT BURNERS

COMPANY NAME	LOCATION	PERMIT ISSUANCE DATE	PROCESS	RATED HEAT INPUT[a] (MMBtu/hr)	POLLUTANT	CONTROL METHOD CODE[b]	CONTROL METHOD	BASIS	EMISSION LIMIT (lb/MMBtu)	(ppm @ 15% O_2)	(lb/hr)	CONTROL EFFICIENCY
Unknown[c]	Louisiana	02/01/97	Turbine, Combustion	500	NO_x	P	Dry Low NO_x Burners	Unknown		9		Unknown
Unocal	Wilmington, California	07/18/89	Westinghouse Model CW251B10 Gas Turbine	Unknown	NO_x	B	SCR, Water Injection	BACT-OTHER		9		80
WEPCU, Paris Site	Paris, Wisconsin	08/29/92	Turbines, Combustion (4)	Unknown	NO_x	P	Good Combustion Practices	BACT-PSD		25		0
West Campus Cogeneration Company	College Station, Texas	05/02/94	2 Gas Turbines [Information represents the 2 turbines combined]	75.3 MW	NO_x	P	Internal Combustion Controls	BACT-PSD			200 tpy	0
Williams Field Services Co. - El Cedro Compressor	Blanco, New Mexico	10/29/93	Turbine, Gas Fired	11257 hp	NO_x	P	Dry Low NO_x Combustor	BACT-PSD		42		66

(a) Rated heat input for *each* combustion unit unless otherwise noted.

(b) RBLC Control Method Codes are as follows:

A = Add-on control equipment
B = Both pollution prevention and add-on equipment
N = No feasible controls
P = Pollution prevention techniques, e.g., any required process modification, change in raw material, or management practice designed to decrease or prevent emissions.
ND = No determination was made.

(c) Information obtained from contacting various states and is not represented in the RBLC. Some of the information was withheld by the respective states and is shown as "unknown."

6. AIR QUALITY MODELING ANALYSIS

This section presents the results of the air quality dispersion analysis performed for the proposed project, and describes the specific procedures used in the analysis. The analysis was conducted in accordance with the procedures outlined in the letter protocol submitted to FDEP and dated 21 February 1997, and subsequent communications with FDEP.

6.1 AIR QUALITY MODEL SELECTION

The intent of the air quality modeling analysis was to determine if the proposed cogeneration facility will have a significant impact, as defined by U.S. EPA significance levels, on the surrounding air quality. In order to accomplish this determination, the U.S. EPA Industrial Source Complex short-term (ISCST3 Version 97363) and SCREEN3 models were used to estimate the short-term and long-term impacts from the cogeneration facility. The input information used in the two models is described in the following sections.

Refined Model Selection

The ISCST3 model (Version 97363) is a U.S. EPA approved air dispersion model that can be used to estimate ambient concentrations in an urban or rural, flat terrain location such as the area surrounding the cogeneration facility. The ISCST3 air dispersion model can predict short-term and long-term concentrations from single or multiple stacks. The ISCST3 air dispersion model can also account for the effects of aerodynamic downwash of a stack's plume by nearby structures. The ISCST3 air dispersion model accepts hourly meteorological data to define the conditions for plume rise, transport, and dispersion. The model estimates the concentration for each source and receptor combination for each hour.

The technical approach and modeling information used in the refined air quality analysis followed the requirements outlined in U.S. EPA "Guidelines in Air Quality Models" 40 CFR Part 51 Appendix W. As part of these requirements, the U.S. EPA recommends regulatory default options for the ISCST3 model. These options, which were used in the refined air quality modeling analysis, are listed below.

- Stack Tip Downwash.
- Final Plume Rise.
- Buoyancy-Induced Dispersion.
- Default Vertical Potential Gradient.
- Default Wind Profile Exponents.
- Upper Bound Value for Supersquat Buildings.
- No Exponential Decay for Rural Mode.
- Use Calms Processing Routine.
- No Use of Missing Data Processing Routine.

6.2 TOPOGRAPHIC SETTING

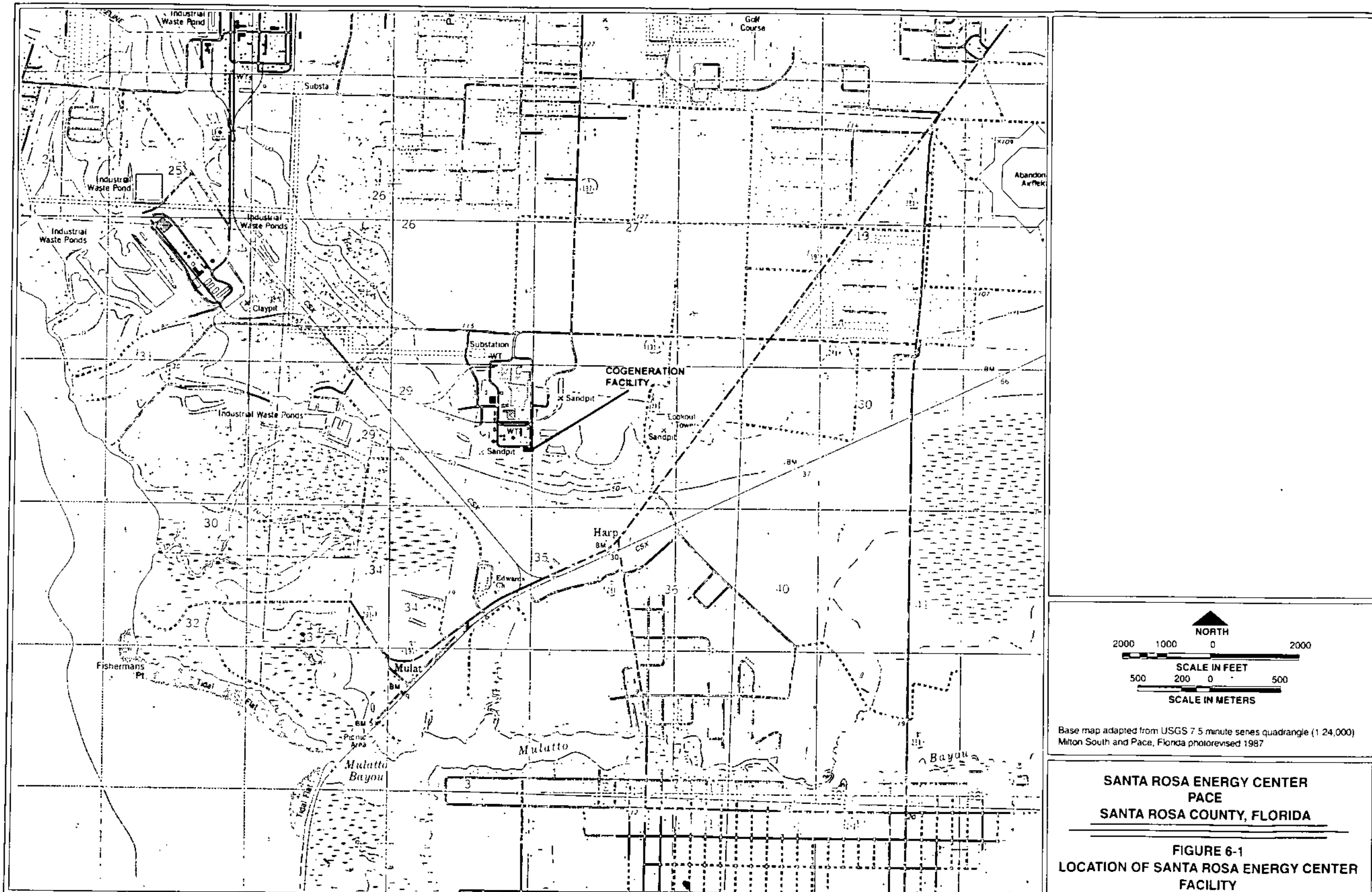
The Santa Rosa Energy Center facility is located in Pace, Santa Rosa County approximately 6 miles (9.6 km) to the northeast of the city of Pensacola. The Santa Rosa Energy Center is in an industrial setting, however a significant amount of the surrounding area is comprised of swamp and undeveloped land. The proposed cogeneration facility will be located near the southeast corner of the Sterling Fibers facility. A map showing the location of the proposed project relative to the surrounding area is provided as Figure 6-1. The base elevation at the proposed location is 90 feet (ft) above mean sea level (amsl). The Universal Transverse Mercator (UTM) coordinates for the proposed cogeneration facility are.

488,970 meters Easting

3,381,390 meters Northing

UTM Zone 16

The topography surrounding the Sterling Fibers facility is generally flat with isolated, distant areas where the terrain rises to 200 ft amsl. The closest area of 200 ft amsl elevation is approximately 18 km north-northwest of the facility. Due to the lack of terrain features approaching stack-top elevation, no terrain elevations were included in the modeling analysis (i.e., flat terrain was assumed).



Base map adapted from USGS 7.5 minute series quadrangle (1:24,000) Milton South and Pace, Florida photorevised 1987

SANTA ROSA ENERGY CENTER
PACE
SANTA ROSA COUNTY, FLORIDA

FIGURE 6-1
LOCATION OF SANTA ROSA ENERGY CENTER FACILITY

98P 1350 5/8/98

6.3 WORST-CASE LOAD ANALYSIS

A load analysis was performed to identify the worst-case load conditions for use in the air dispersion modeling analysis. The SCREEN3 model (dated 96043) was used to evaluate dispersion of emissions from the cogeneration unit for five loads (50%, 65%, 75%, 100%, and power augmentation mode) and three seasonal operating conditions (summer, winter, and average). The use of seasonal operating conditions was required due to the differences in operation characteristic (specifically volumetric flow) of the turbine with ambient temperatures. The exhaust stack characteristics used in the load analysis are presented in Table 6-1.

The stack characteristics in Table 6-1 were run with 1 g/s (unity) emission rate in the SCREEN3 model to obtain a worst-case 1-hour concentration for each combination of load and season that was evaluated. The 1-hour results were scaled to longer averaging periods using the SCREEN3 recommended scaling factors of 0.9, 0.7, 0.4, and 0.08 for the 3-hour, 8-hour, 24-hour, and annual averaging periods, respectively. The worst-case load conditions were identified by multiplying the scaled unity concentration by the load and season-specific emission rates, as summarized in Tables 6-2 through 6-6, for the 50%, 65%, 75%, 100%, and power augmentation load conditions, respectively.

As shown in Tables 6-2 through 6-6, the 50% load at summer ambient conditions (Table 6-2) produces the worst-case screening impacts for all pollutants except NO_X and CO. For NO_X and CO, the worst-case operating condition for stack flow, stack temperature, and pollutant emission rates were in power augmentation mode during the summer season. Therefore, the summer 50% load conditions were selected to represent worst-case short-term (up to 24-hour average) operating conditions. Since the 50% condition does not represent typical operating conditions, the power augmentation mode summer condition was chosen as a conservative representation of long-term (annual average) operations. The pollutant emission rates used for the power augmentation modeling corresponded to the winter season pollutant emission rates. The winter season rates are the maximum hourly emission rates to be contained in the cogeneration facilities operating permit and thus were included in the modeling analysis to maintain consistency.

TABLE 6-1
POLSKY ENERGY CORPORATION
PROPOSED GAS TURBINE PROJECT
SANTA ROSA ENERGY CENTER
PHYSICAL STACK CHARACTERISTICS FOR MODELING
BASED ON THE FIRING OF NATURAL GAS

BASE LOAD	AMBIENT CLIMATE CONDITIONS	COMPRESSOR INLET TEMP.	STACK PARAMETERS				Emission Rates (Turbine and Duct Burner) [h]									
			TEMP.[a]	VELOCITY[b]	DIAMETER[c]	HEIGHT[d]	PM/PM_{10}		SO_2 (Insignificant)		NO_x		VOC (Insignificant)		CO (Insignificant)	
		(°F)	(K)	(m/sec)	(m)	(m)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)
STIG	Winter[e]	40	375	19.6	5.8	61.0	14.2	1.8	1.7	0.2	136.1	17.1	14.3	1.8	14.9	1.9
	Average[f]	68	375	18.9	5.8	61.0	14.2	1.8	1.7	0.2	132.9	16.7	14.3	1.8	14.4	1.8
	Summer[g]	92	375	18.1	5.8	61.0	14.2	1.8	1.7	0.2	128.7	16.2	14.0	1.8	14.1	1.8
100%	Winter[e]	40	369	18.3	5.8	61.0	14.2	1.8	1.7	0.2	110.9	14.0	14.0	1.8	11.7	1.5
	Average[f]	68	369	17.6	5.8	61.0	14.2	1.8	1.7	0.2	108.8	13.7	14.0	1.8	11.4	1.4
	Summer[g]	92	369	16.9	5.8	61.0	14.2	1.8	1.7	0.2	105.6	13.3	13.8	1.7	11.3	1.4
75%	Winter[e]	40	365	14.7	5.8	61.0	14.2	1.8	1.7	0.2	98.3	12.4	13.4	1.7	10.8	1.4
	Average[f]	68	365	14.3	5.8	61.0	14.2	1.8	1.7	0.2	96.2	12.1	13.4	1.7	10.7	1.3
	Summer[g]	92	365	13.8	5.8	61.0	14.2	1.8	1.7	0.2	94.1	11.9	13.4	1.7	10.5	1.3
65%	Winter[e]	40	365	13.6	5.8	61.0	14.2	1.8	1.7	0.2	94.1	11.9	13.4	1.7	10.5	1.3
	Average[f]	68	365	13.3	5.8	61.0	14.2	1.8	1.7	0.2	92.0	11.6	13.4	1.7	10.5	1.3
	Summer[g]	92	365	12.9	5.8	61.0	14.2	1.8	1.7	0.2	89.9	11.3	13.2	1.7	10.3	1.3
50%	Winter[e]	40	364	12.1	5.8	61.0	14.2	1.8	1.7	0.2	87.8	11.1	13.2	1.7	10.2	1.3
	Average[f]	68	364	11.8	5.8	61.0	14.2	1.8	1.7	0.2	86.7	10.9	13.0	1.6	10.0	1.3
	Summer[g]	92	364	11.5	5.8	61.0	14.2	1.8	1.7	0.2	84.6	10.7	13.0	1.6	10.0	1.3

[a] Provided by Polsky. Exhaust temperature assumed to be equal for all ambient conditions by load.
[b] Assumed exhaust velocity in order to "back-calculate" stack diameter for 100% baseload winter case while firing natural gas. Assume same diameter for all other cases.
[c] Stack diameter "back-calculated" based on assumed exhaust velocity of 60 ft/min for 100% load at 40 °F.
[d] Stack height of 200 ft. based on information from Polsky.
[e] Represents January daily minimum temperature.
[f] Represents the annual average temperature.
[h] Represents average summer ambient climate conditions
[g] Emissions include the conservative assumption of the duct burner firing at maximum capacity for all turbine loads and ambient conditions.
[i] Insignificant indicates that the pollutant's annual emissions potential is below the PSD significant increase threshold thus not subject to PSD review.

TABLE 6-2
WORST-CASE LOAD SCREENING ANALYSIS: 50% BASE LOAD
POLSKY ENERGY CORPORATION
PROPOSED COGENERATION PROJECT
SANTA ROSA ENERGY CENTER

POLLUTANT NAME	50% LOAD CONDITION TOTAL EMISSION RATES [a] (lb/hr)			50% LOAD CONDITION - WINTER(b) (c)					50% LOAD CONDITION - AVERAGE(b) (c)					50% LOAD CONDITION - SUMMER(b) (c)				
	WINTER	AVERGAGE	SUMMER	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)
GAS TURBINE FIRING NATURAL GAS (INCLUDES DUCT BURNERS FIRING NATURAL GAS)																		
Total Suspended Particulates	14.2	14.2	14.2	0.420	2.099	-	-	-	0.427	2.137	-	-	-	0.435	2.176	-	-	-
PM10	14.2	14.2	14.2	0.420	2.099	-	-	-	0.427	2.137	-	-	-	0.435	2.176	-	-	-
Sulfur Dioxide	1.7	1.7	1.7	0.050	0.251	-	0.565	-	0.051	0.256	-	0.576	-	0.052	0.261	-	0.586	-
Nitrogen Oxides	87.8	86.7	84.6	**2.596**	-	-	-	-	**2.610**	-	-	-	-	**2.593**	-	-	-	-
Carbon Monoxide	67.8	66.8	66.8	-	-	17.5	-	25.1	-	-	17.6	-	25.1	-	-	17.9	-	25.6

[a] Hourly emission rates for turbine and duct burner, based on vendor-supplied values at various ambient climate conditions.

[b] Concentrations predicted by SCREEN3 model for simple terrain.

[c] The following averaging time conversion factors were used to convert the maximum one-hour concentration to the following averaging periods:

Annual conversion factor:	0.08
24-hour conversion factor:	0.4
8-hour conversion factor:	0.7
3-hour conversion factor:	0.9
1-hour conversion factor:	1.0

NOTE: Boldfaced values are above PSD significance levels.

TABLE 6-3
WORST-CASE LOAD SCREENING ANALYSIS: 65% BASE LOAD
POLSKY ENERGY CORPORATION
PROPOSED COGENERATION PROJECT
SANTA ROSA ENERGY CENTER

POLLUTANT NAME	65% LOAD CONDITION TOTAL EMISSION RATES [a] (lb/hr)			65% LOAD CONDITION - WINTER(b) (c)					65% LOAD CONDITION - AVERAGE(b) (c)					65% LOAD CONDITION - SUMMER(b) (c)				
	WINTER	AVERGAGE	SUMMER	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)
GAS TURBINE FIRING NATURAL GAS (INCLUDES DUCT BURNERS FIRING NATURAL GAS)																		
Total Suspended Particulates	14.2	14.2	14.2	0.389	1.947	-	-	-	0.395	1.975	-	-	-	0.402	2.012	-	-	-
PM10	14.2	14.2	14.2	0.389	1.947	-	-	-	0.395	1.975	-	-	-	0.402	2.012	-	-	-
Sulfur Dioxide	1.7	1.7	1.7	0.047	0.233	-	0.525	-	0.047	0.236	-	0.532	-	0.048	0.241	-	0.542	-
Nitrogen Oxides	94.1	92.0	89.9	**2.581**	-	-	-	-	**2.560**	-	-	-	-	**2.548**	-	-	-	-
Carbon Monoxide	69.9	69.9	68.9	-	-	16.8	-	24.0	-	-	17.0	-	24.3	-	-	17.1	-	24.4

[a] Hourly emission rates for turbine and duct burner, based on vendor-supplied values at various ambient climate conditions.

[b] Concentrations predicted by SCREEN3 model for simple terrain.

[c] The following averaging time conversion factors were used to convert the maximum one-hour concentration to the following averaging periods:

Annual conversion factor:	0.08
24-hour conversion factor:	0.4
8-hour conversion factor:	0.7
3-hour conversion factor:	0.9
1-hour conversion factor:	1.0

NOTE: Boldfaced values are above PSD significance levels

TABLE 6-4
WORST-CASE LOAD SCREENING ANALYSIS: 75% BASE LOAD
POLSKY ENERGY CORPORATION
PROPOSED COGENERATION PROJECT
SANTA ROSA ENERGY CENTER

POLLUTANT NAME	75% LOAD CONDITION TOTAL EMISSION RATES [a] (lb/hr)			75% LOAD CONDITION - WINTER(b) (c)					75% LOAD CONDITION - AVERAGE(b) (c)					75% LOAD CONDITION - SUMMER(b) (c)				
	WINTER	AVERGAGE	SUMMER	ANNUAL (μg/m³)	24-HOUR (μg/m³)	8-HOUR (μg/m³)	3-HOUR (μg/m³)	1-HOUR (μg/m³)	ANNUAL (μg/m³)	24-HOUR (μg/m³)	8-HOUR (μg/m³)	3-HOUR (μg/m³)	1-HOUR (μg/m³)	ANNUAL (μg/m³)	24-HOUR (μg/m³)	8-HOUR (μg/m³)	3-HOUR (μg/m³)	1-HOUR (μg/m³)
GAS TURBINE FIRING NATURAL GAS (INCLUDES DUCT BURNERS FIRING NATURAL GAS)																		
Total Suspended Particulates	14.2	14.2	14.2	0.370	1.851	-	-	-	0.377	1.885	-	-	-	0.386	1.929	-	-	-
PM10	14.2	14.2	14.2	0.370	1.851	-	-	-	0.377	1.885	-	-	-	0.386	1.929	-	-	-
Sulfur Dioxide	1.7	1.7	1.7	0.044	0.222	-	0.499	-	0.045	0.226	-	0.508	-	0.046	0.231	-	0.520	-
Nitrogen Oxides	98.3	96.2	94.1	**2.562**	-	-	-	-	**2.554**	-	-	-	-	**2.557**	-	-	-	-
Carbon Monoxide	72.0	71.0	69.9	-	-	16.4	-	23.5	-	-	16.5	-	23.6	-	-	16.6	-	23.7

[a] Hourly emission rates for turbine and duct burner, based on vendor-supplied values at various ambient climate conditions.

[b] Concentrations predicted by SCREEN3 model for simple terrain.

[c] The following averaging time conversion factors were used to convert the maximum one-hour concentration to the following averaging periods.

Annual conversion factor:	0.08
24-hour conversion factor:	0.4
8-hour conversion factor:	0.7
3-hour conversion factor:	0.9
1-hour conversion factor:	1.0

NOTE: Boldfaced values are above PSD significance levels.

TABLE 6-5
WORST-CASE LOAD SCREENING ANALYSIS: 100% BASE LOAD
POLSKY ENERGY CORPORATION
PROPOSED COGENERATION PROJECT
SANTA ROSA ENERGY CENTER

POLLUTANT NAME	100% LOAD CONDITION TOTAL EMISSION RATES [a] (lb/hr)			100% LOAD CONDITION - WINTER(b) (c)					100% LOAD CONDITION - AVERAGE(b) (c)					100% LOAD CONDITION - SUMMER(b) (c)				
	WINTER	AVERGAGE	SUMMER	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)
GAS TURBINE FIRING NATURAL GAS (INCLUDES DUCT BURNERS FIRING NATURAL GAS)																		
Total Suspended Particulates	14.2	14.2	14.2	0.309	1.547	-	-	-	0.319	1.597	-	-	-	0.330	1.650	-	-	-
PM10	14.2	14.2	14.2	0.309	1.547	-	-	-	0.319	1.597	-	-	-	0.330	1.650	-	-	-
Sulfur Dioxide	1.7	1.7	1.7	0.037	0.185	-	0.417	-	0.038	0.191	-	0.430	-	0.039	0.197	-	0.444	-
Nitrogen Oxides	110.9	108.8	105.6	**2.417**	-	-	-	-	**2.448**	-	-	-	-	**2.454**	-	-	-	-
Carbon Monoxide	78.3	76.2	75.2	-	-	14.9	-	21.3	-	-	15.0	-	21.4	-	-	15.3	-	21.8

[a] Hourly emission rates for turbine and duct burner, based on vendor-supplied values at various ambient climate conditions.

[b] Concentrations predicted by SCREEN3 model for simple terrain.

[c] The following averaging time conversion factors were used to convert the maximum one-hour concentration to the following averaging periods:

Annual conversion factor:	0.08
24-hour conversion factor:	0.4
8-hour conversion factor:	0.7
3-hour conversion factor:	0.9
1-hour conversion factor:	1.0

NOTE: Boldfaced values are above PSD significance levels.

TABLE 6-6
WORST-CASE LOAD SCREENING ANALYSIS: POWER AUGMENTATION MODE
POLSKY ENERGY CORPORATION
PROPOSED COGENERATION PROJECT
SANTA ROSA ENERGY CENTER

	POWER AUGMENTATION MODE TOTAL EMISSION RATES [a] (lb/hr)			POWER AUGMENTATION MODE - WINTER(b) (c)					POWER AUGMENTATION MODE MODE - AVERAGE(b) (c)					POWER AUGMENTATION MODE MODE - SUMMER(b) (c)				
POLLUTANT NAME	WINTER	AVERGAGE	SUMMER	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)	ANNUAL ($\mu g/m^3$)	24-HOUR ($\mu g/m^3$)	8-HOUR ($\mu g/m^3$)	3-HOUR ($\mu g/m^3$)	1-HOUR ($\mu g/m^3$)
GAS TURBINE FIRING NATURAL GAS (INCLUDES DUCT BURNERS FIRING NATURAL GAS)																		
Total Suspended Particulates	14.2	14 2	14.2	0.285	1.427	-	-	-	0 295	1.474	-	-	-	0 306	1.529	-	-	-
PM10	14.2	14 2	14.2	0.285	1.427	-	-	-	0.295	1.474	-	-	-	0.306	1.529	-	-	-
Sulfur Dioxide	1 7	1 7	1.7	0.034	0 171	-	0.384	-	0.035	0.176	-	0.397	-	0 037	0.183	-	0.412	-
Nitrogen Oxides	136.1	132.9	128.7	**2.736**	-	-	-	-	**2.758**	-	-	-	-	**2.771**	-	-	-	-
Carbon Monoxide	99 3	96.2	94.1	-	-	17.5	-	24.9	-	-	17.5	-	25 0	-	-	17.7	-	25.3

[a] Hourly emission rates for turbine and duct burner, based on vendor-supplied values at various ambient climate conditions.

[b] Concentrations predicted by SCREEN3 model for simple terrain

[c] The following averaging time conversion factors were used to convert the maximum one-hour concentration to the following averaging periods:

Annual conversion factor	0.08
24-hour conversion factor	0.4
8-hour conversion factor	0 7
3-hour conversion factor	0 9
1-hour conversion factor	1.0

NOTE: Boldfaced values are above PSD significance levels.

[SM]D \SAROSA\SCREENING\
LoadImpacts xls | STIG

15:52

6.4 AUER LAND USE DETERMINATION

A land use analysis was performed for the 3 km radius surrounding the proposed cogeneration facility. The land use analysis was performed following the procedures described by Auer. Inspection of the USGS topographic maps of the surrounding area indicates no industrial or urban areas, aside from the Sterling Fibers facility. Based upon this determination, the rural dispersion option in the ISCST3 and SCREEN3 models was used. Figure 6-2 shows the land use analysis.

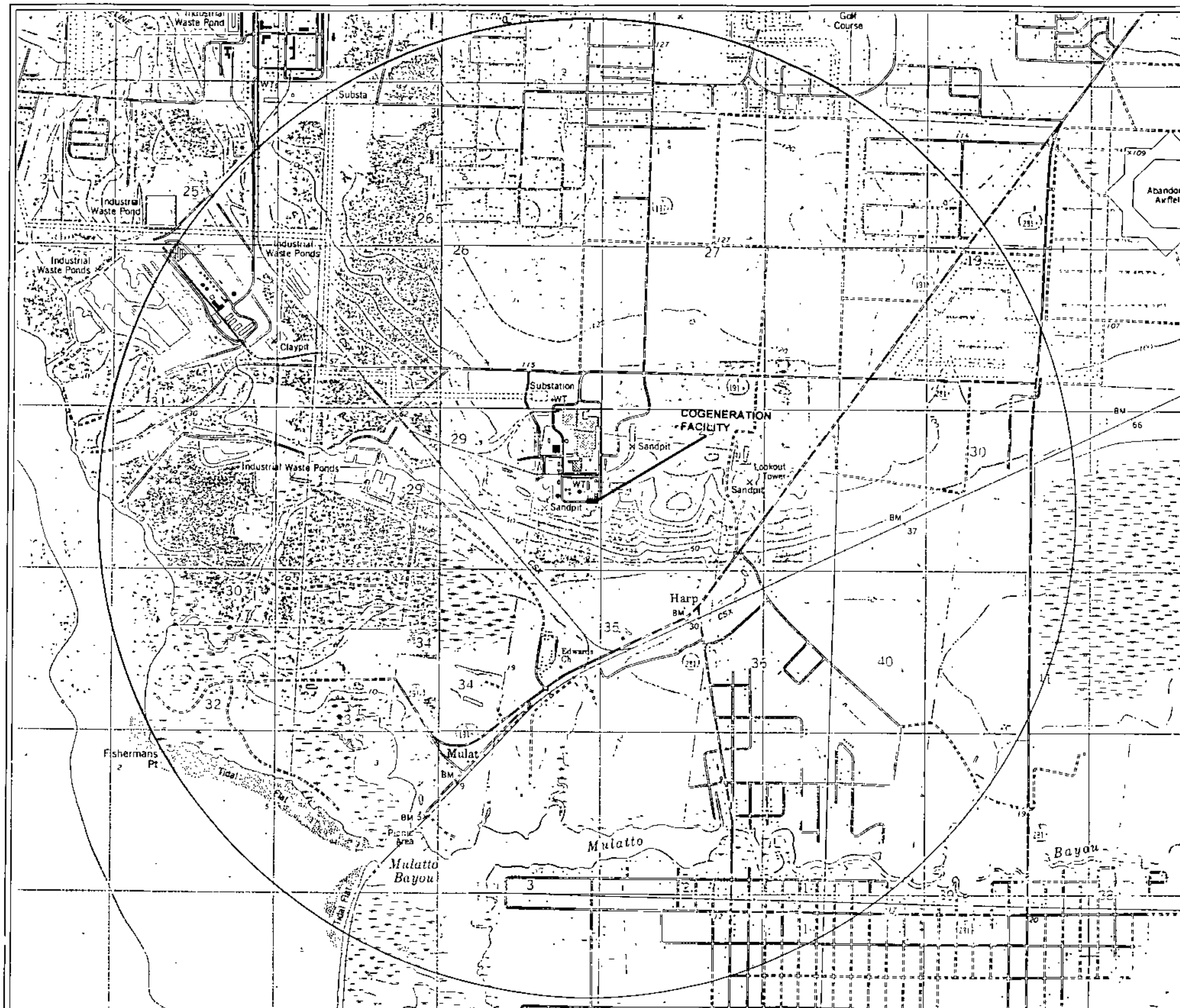
6.5 RECEPTOR GRID

For the ISCST3 receptor grid, a Cartesian coordinate system was used. The ISCST3 receptor grid consisted of a rectangular grid with 20 km by 20 km dimensions centered approximately on the cogeneration facility stack. The inner portion of the grid had grid cells at 100 meter (m) spacing out to 1,000 m. A 200 m spacing was used out to 3,000 m, and a 500 m spacing was used out to 5,000 m. From 5,000 m to 10,000 m, a 1,000 m spacing was used to develop the grid cells. Since flat terrain was assumed, no terrain elevations were determined for any receptor. Figure 6-3 shows the inner portion of the receptor grid.

The grid origin was located at the cogeneration unit stack. There is no restricted access at the Sterling Fibers facility. Therefore, no receptors were removed from the grid, and the adjoining Sterling Fibers facility was considered as ambient air.

6.6 METEOROLOGICAL DATA

The meteorological data that were used in the air quality modeling analysis consisted of screening meteorological data and five years of National Weather Service (NWS) data. The SCREEN3 model used a matrix of screening meteorological conditions to estimate the worst-case air impacts. For the ISCST3 air quality modeling, five years of NWS data from the Pensacola Regional Airport, from the 1985 - 1989 period were used. The Pensacola Airport is 12.5 km to the southwest of the facility and is representative of the local meteorological conditions.



LEGEND: LAND USE/LAND COVER

Classification/ Category		Description
URBAN	I1/I2	Major industrial (all levels) and major transportation
	C1	Major commercial (large areas only)
	R2/R3	Residential (urban) - dense development with other uses interspersed (industrial, commercial, institutional, etc.)
RURAL	R1/R4	Residential (suburban/rural) - varying densities (may include minor areas of other uses)
		Open Space
	A1	Metropolitan natural - parks, institutional cemeteries
	A2/A3	Undeveloped/disturbed - rural agricultural
	A4	Undeveloped - woodlands, marshes
	A5	Surface water - impoundments

NOTE:

1. Land use/land cover developed from USGS 7.5 min. series quadrangles photo-revised 1995, land use/land cover categories are for this date and are generalized to meet air quality modeling requirements
2. Land use/land cover categories are based on US EPA Guidelines on Air Quality Models (revised 7/1986) and on Auer, A.H., JAM Volume 17, pp 636 - 643, 1978.
3. Not all land use/land cover categories are found in the 3Km radius area.

NORTH

2000 1000 0 2000
SCALE IN FEET

500 200 0 500
SCALE IN METERS

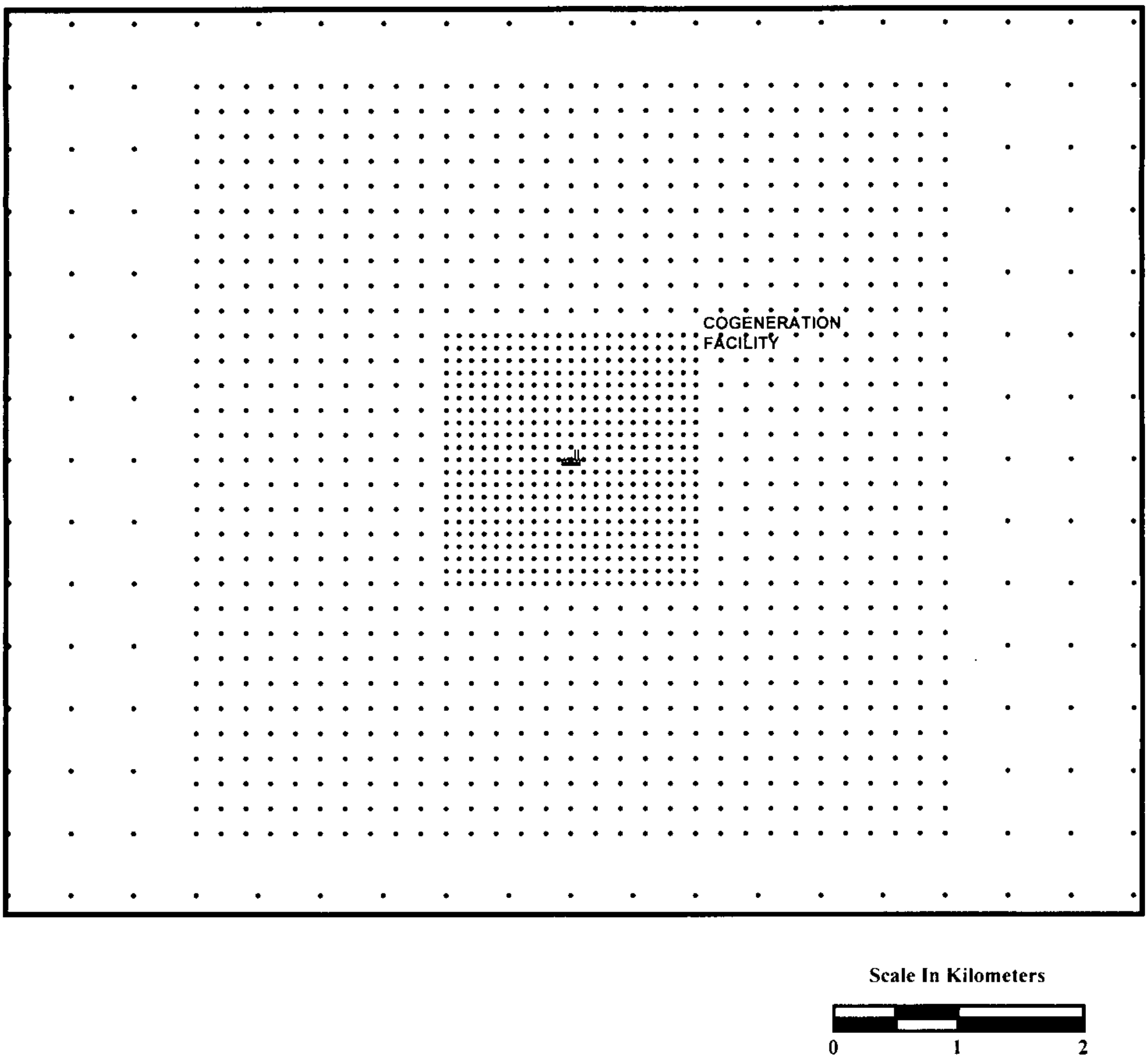
SOURCE:
Base map adapted from USGS 7.5 minute series quadrangle (1:24,000) Milton South and Pace, Florida photorevised 1987

SANTA ROSA ENERGY CENTER
PACE
SANTA ROSA COUNTY, FLORIDA

FIGURE 6-2
GENERALIZED LAND USE/LAND COVER ANALYSIS WITHIN A 3 KILOMETER (1.8 MILE) RADIUS

98P-1351 5/8/98

FIGURE 6-3
INNER PORTION OF ISC3 RECEPTOR GRID
SANTA ROSA ENERGY CENTER
PACE, FLORIDA



Concurrent upper air data from Apalachicola, FL were used to generate mixing heights for the ISC3 model.

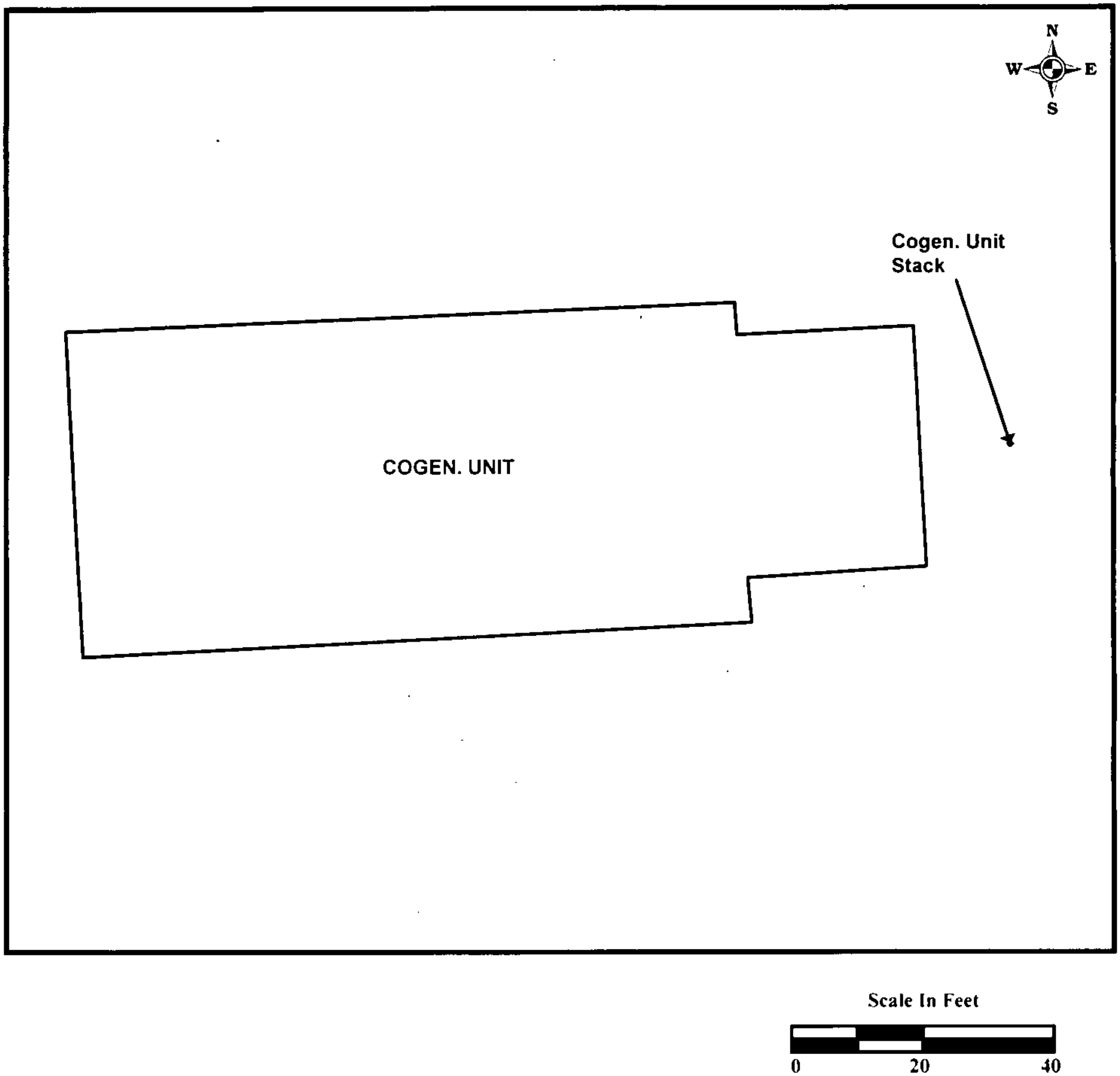
6.7 BUILDING DOWNWASH ANALYSIS

A Good Engineering Practice (GEP) stack height analysis was performed to evaluate the potential for building aerodynamic downwash as well as the presence of cavity zones. The GEP analysis was performed using available plot plans. The US EPA Building Profile Input Program (BPIP Version 95086) was used to evaluate the potential for building downwash.

The stack height of the proposed cogeneration facility is 200 ft Therefore, a building would have to have a minimum height of 80 ft in order to influence the cogeneration stack (i.e., 2.5 x L where L is height and is less than the building width). The only structure taller than 80 ft in the vicinity of the cogeneration stack is the cogeneration unit itself. The entire cogeneration unit was assumed to be at the height of its tallest portion, at 90 ft above ground. Figure 6-4 shows the orientation of the cogeneration unit and the relative location of the stack.

The GEP height analysis indicated that the cogeneration unit produces a GEP height of 225 ft (68.58 m) for the cogeneration stack. Since the proposed cogeneration stack height of 200 ft is below the 225 ft GEP height, the stack is considered to be subject to building-induced downwash, and building dimensions were included in the ISCST3 and SCREEN3 modeling analyses. A cavity analysis based on the cogeneration unit and the Schulman and Scire wake cavity algorithm in SCREEN3 indicated that the maximum cavity concentration was less than any of the non-cavity concentrations.

FIGURE 6-4
BUILDING CONFIGURATION USED IN BPIP ANALYSIS
SANTA ROSA ENERGY CENTER
PACE, FLORIDA



6.8 SUMMARY OF AIR QUALITY MODELING RESULTS

The worst-case load analysis with SCREEN3 indicated that the worst-case load conditions were power augmentation mode (NO_x) and 50% load (all other pollutants) under summer ambient conditions. For the ISCST3 modeling, the stack characteristics for the 50% load and power augmentation modes with summer ambient conditions were used. The 50% condition was used to represent the worst-case short-term operating scenario, and the power augmentation condition was used conservatively represent long-term operations.

The PSD significance levels used in evaluating the modeling results are presented in Table 6-7. The results of the ISCST3 modeling are presented in Table 6-8. Table 6-8 demonstrates that the maximum potential impacts from the proposed cogeneration stack will be below the PSD significance levels. Therefore, the proposed project will not cause or contribute to ambient air quality concentrations that exceed the NAAQS or PSD increments.

PSD regulations require the analyses be conducted to determine whether the proposed project will have detrimental impacts on other air quality related values (AQRVs) in the vicinity of the project (Class II area) or and Class I areas within 100 km of the project. Examples of AQRVs include visibility, biological or ecological communities, and scenic, cultural, physical, or recreational resources. Since the proposed cogeneration project's air quality impacts in the immediate vicinity are well below the PSD significance levels, local AQRVs or AQRVs at distant Class I areas should be not affected by the project. Therefore, no detailed AQRV analysis was performed.

TABLE 6-7
PSD SIGNIFICANCE LEVELS
SANTA ROSA ENERGY CENTER PROPOSED COGENERATION PROJECT

	PSD SIGNIFICANCE LEVELS ($\mu g/m^3$) AVERAGING PERIOD				
POLLUTANT	1-HR	3-HR	8-HR	24-HR	ANNUAL
Total Suspended Particulates				5	1
PM10				5	1
Sulfur Dioxide		25		5	1
Nitrogen Oxides					1
Carbon Monoxide	2,000		500		

TABLE 6-8
ISCST3 MODELING RESULTS FOR
SANTA ROSA ENERGY CENTER PROPOSED COGENERATION PROJECT

POLLUTANT	TOTAL MAXIMUM EMISSIONS		MODELED MAXIMUM AMBIENT IMPACT FOR ALL RECEPTORS ($\mu g/m^3$) [a] AVERAGING PERIOD				
	(lb/hr)	(g/s)	1-HR	3-HR	8-HR	24-HR	ANNUAL
POWER AUGMENTATION MODE							
Unity Modeled Concentration ($\mu g/m^3$)/(g/s)	-----	1.00	1.9316	0.6439	0.3219	0.1382	0.00702
Total Suspended Particulates	14.2	1.79				0.25	0.01
PM10	14.2	1.79				0.25	0.01
Sulfur Dioxide	1.7	0.21		0.14		0.03	0.002
Nitrogen Oxides [c]	136.1	17.15					0.12
Carbon Monoxide [c]	99.3	12.51	24.17		4.03		
50% LOAD CONDITION [b]							
Unity Modeled Concentration ($\mu g/m^3$)/(g/s)	-----	1.00	3.6658	1.4118	0.6482	0.3093	0.01203
Total Suspended Particulates	14.2	1.79				0.55	0.02
PM10	14.2	1.79				0.55	0.02
Sulfur Dioxide	1.7	0.21		0.30		0.07	0.003
Nitrogen Oxides [c]	87.8	11.06					0.13
Carbon Monoxide [c]	67.8	8.54	31.32		5.54		

NOTES

[a] - Maximum ISCST3 modeled concentration for five-year period 1985-1989, unless otherwise indicated.
[b] - 50% load assumed for turbine only. Duct burner emissions are for 100% load.
[c] - Emission rates for winter climate conditions, which are higher than for summer conditions, were used.

APPENDIX A
FDEP AIR PERMITTING APPLICATION FORMS

FLORIDA DEP LOGO

Department of Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

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

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

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: *Sterling Fibers Inc., 5005 Sterling Way* City: *Pace* County: *Santa Rosa* Zip Code: *32571*	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	July 8, 1998
2. Permit Number:	1130003-005-AC
3. PSD Number (if applicable):	PSD-FL-253
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
James Shield *Vice President - Engineering and Project Management*

2. Owner/Authorized Representative or Responsible Official Mailing Address:

Organization/Firm: *Santa Rosa Energy LLC*
Street Address: *650 Dundee Road, Suite 150*
City: *Northbrook* State: *IL* Zip Code: *60062*

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
Telephone: *(847) 559-9800* Fax: *(847) 559-1805*

4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

James S. Shield

Signature

7/6/98

Date

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID	Description of Emissions Unit	Permit Type
GT-0001	*168 MWe (nominal) Natural Gas Fired Combustion Turbine*	*AC1A*
HSRG-0001	*585 MMBtu/hr (annual fuel limited to 3,280 x 10^6 scf) Natural Gas Fired Duct Burner for the Heat Recovery Steam Generator with <75 MWe Steam Electric Turbine*	*AC1A*

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C. *N/A*

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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: ______________________________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: ______________________________

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

Current construction permit number: ______________________________

Operation permit to be revised: ______________________________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: ______________________________

[ ] Air operation permit revision for a Title V source 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 to be revised: ______________________________

Reason for revision: ______________________________

____

Category II: All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C. *N/A*

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______________________________

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______________________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______________________________

Reason for revision: ______________________________

____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain:

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: ______________________________

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

Current operation permit number(s): ______________________________

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

Application Processing Fee

Check one:

[X] Attached - Amount: $ *7,500* [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations: *Installation of a natural gas-fired combustion turbine, a heat recovery steam generator (HSRG) with natural gas-fired duct burner, a steam turbine (<75MWe), and all associated auxiliary equipment. (please see Section 2.2 of the report text)*
2. Projected or Actual Date of Commencement of Construction: *Summer 1998 or after construction approval.*
3. Projected Date of Completion of Construction: *Approximately 5 months after construction commences.*

Professional Engineer Certification

1. Professional Engineer Name: *Mark Eugene Cramer* Registration Number: *0050182*
2. Professional Engineer Mailing Address: Organization/Firm: *Roy F. Weston, Inc.* Street Address: *1000 Perimeter Park Drive, Suite E* City: *Morrisville* State: *NC* Zip Code: *27560-9658*

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 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, 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 and EPA emission factors.

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 [X] 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.

[signature] 6/18/98

Signature Date
(seal)

DEP Form No. 62-210.900(1) - Form
Effective: 3-21-96

Application Contact

1. Name and Title of Application Contact: *Craig Carson, Project Manager*
2. Application Contact Mailing Address: Organization/Firm: *Santa Rosa Energy LLC* Street Address: *650 Dundee Road, Suite 150* City: *Northbrook* State: *IL* Zip Code: *60062*
3. Application Contact Telephone Numbers: Telephone: *(847) 559-9800* Fax: *(847) 559-1805*

Application Comment

Mr. Carson will be in Pace, Florida frequently during construction. A local address and telephone number will be provided after construction has begun.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: *16* East (km): *488,970* North (km): *3,381.350*			
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): *Please see Section 2.1 of the report text for additional information.* *Santa Rosa Energy LLC's cogeneration facility is a separate facility from Sterling Fibers.*			

Facility Contact

1. Name and Title of Facility Contact: *Jimmy Lay* *Environmental Affairs Manager*
2. Facility Contact Mailing Address: Organization/Firm: *Sterling Fibers Inc.* Street Address: *5005 Sterling Way* City: *Pace* State: *FL* Zip Code: *32571*
3. Facility Contact Telephone Numbers: Telephone: *(850) 994-9800* Fax: *(850) 994-2606*

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes	[X] No	[ ] Unknown
2. Title V Source? [X] Yes	[ ] No	
3. Synthetic Non-Title V Source? [ ] Yes	[X] No	
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [X] Yes	[ ] No	
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes	[X] No	
6. Major Source of Hazardous Air Pollutants (HAPs)? [ ] Yes	[X] No	
7. Synthetic Minor Source of HAPs? [ ] Yes	[X] No	
8. One or More Emissions Units Subject to NSPS? [X] Yes	[ ] No	
9. One or More Emission Units Subject to NESHAP? [ ] Yes	[X] No	
10. Title V Source by EPA Designation? [X] Yes	[ ] No	
11. Facility Regulatory Classifications Comment (limit to 200 characters): *A federally enforceable restriction is being requested on limiting the duct burner's annual natural gas consumption to 3,280 x 10^6 scf (~64% annual capacity).* *Please see Section 3.1.2 of the report text for additional information.*		

B. FACILITY REGULATIONS

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable - The facility is a Title V facility.

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

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, Rule 62-204.360	*Designation of Prevention of Significant Deterioration Areas*
Chapter 62-204, Rule 62-204.800	*Federal Regulations Adopted by 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 than 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*

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See 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 (Open 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 Emission Monitoring*
40 CFR Part 60, Subpart A	*General Provisions, New Source Performance Standards*
40 CFR Part 60, Subpart Da (60.40a through 60.49a)	*Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978 (Applicable to Duct Burner Only)*
40 CFR Part 60, Subpart GG (60.330 through 60.335)	*Standards of Performance for Stationary Gas Turbines*
See Section 4 of the report text for additional information.	

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
CO	*A*
NOX	*A*
PM	*B*
PM10	*B*
SO2	*B*
VOC	*B*
HAP	*B*

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information: Pollutant ___1___ of ___1___

1. Pollutant Emitted: *Not Applicable, No Facility-wide or Multi-unit Emissions Cap is Requested*		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): *Emissions are proposed to be limited on a unit basis only.*		

Facility Pollutant Detail Information: Pollutant ______ of ______

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location: [X] Attached, Document ID:_*Fig. 2-1* [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [X] Attached, Document ID:_*Fig. 2-2* [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [X] Attached, Document ID:_ *Fig. 2-3* [ ] Not Applicable [ ] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID:_*Section 4.2.1*[ ] Not Applicable [ ] Waiver Requested *Please see Section 4.2.1 of the report text.*	
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID:_*See Report with Appendices B - D* [ ] Not Applicable	

Additional Supplemental Requirements for Category I Applications Only

Not Applicable, Category I Application to be Submitted after Construction is Completed

7. List of Proposed Exempt Activities: [ ] Attached, Document ID:________ [ ] Not Applicable	
8. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable	
9. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable	
10. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable	

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:_______ [ ] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID:_______ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached, Document ID:_______ [ ] Plan to be Submitted to Implementing Agency by Required Date [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:_______ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:_______ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L 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. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

<u>Type of Emissions Unit Addressed in This Section</u>

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. 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 (note: the duct burner is listed as a separate emitting unit)*		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown *GT-0001*		
3. Emissions Unit Status Code: *C*	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: *49*
6. Emissions Unit Comment (limit to 500 characters): *The combustion turbine will be a General Electric Frame 7F or equivalent. The unit has a nominal rating of 168 MWe at 100% load, 1,772.8 MMBtu/hr (HHV), at an ambient temperature of 68°F. Generating capacity and heat input will vary with seasonal weather conditions. The combustion turbine also has the capability to operate at higher than 100% design load when operated in the "Power Augmentation Mode". The capacity increase during "Power Augmentation Mode" may increase to 189 MWe, 1,908 MMBtu/hr (HHV), at an ambient temperature of 40°F. Operation in the "Power Augmentation Mode" will occur for limited periods due to the high stresses placed on the turbine and as recommended by the manufacturer..*		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): *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: *025*

B.

1. Description (limit to 200 characters): *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: *030*

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: *Approximately 5 months after approval and start of construction.*
2. Long-term Reserve Shutdown Date: *Not Applicable*
3. Package Unit: *Combustion Turbine* Manufacturer: *General Electric or equal* Model Number: *GE MS7001FA or equal*
4. Generator Nameplate Rating: *appr. 159 Simple Cycle and 241 Combined Cycle* MW *Actual name plate rating will be provided when available.*
5. Incinerator Information: *Not Applicable* Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate: mmBtu/hr *1,908 MMBtu/hr @ PWR AUG mode and 40°F 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. Operating Capacity 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.*

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:			
24	hours/day	*7*	days/week
52	weeks/year	*8,760*	hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

<u>Rule Applicability Analysis</u> (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable, The Facility is a Title V source.

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

Chapter 62-204, Rule 62-204.240 (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 air 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 limit of 0.0080% NO_x @15% O_2, dry basis or 80 ppmvd @ 15% O_2, for the 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.*

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

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 system 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.*

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60 §60.334(b) continued	*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 contacted 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.*
See Section 4 of the report text for additional information.	

E. 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 [X] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): *The natural gas-fired combustion turbine exhaust gases will combine with the natural gas fired duct burner's exhaust gases and exit through a common stack.*	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: *GT-0001 and HRSG-0001*	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [X] V [ ] W	
6. Stack Height:	*Appr. 200* feet
7. Exit Diameter:	*Appr. 19* feet
8. Exit Temperature:	*Appr. 196 - 216* °F

9. Actual Volumetric Flow Rate: *See Comments*		*1,073,204* acfm
10. Percent 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): *488.970*	North (km): *3,381.350*

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

Stack diameter calculated assuming an average exhaust velocity (60 fps at 100% load, 40°F). Actual stack diameter to be provided when final design information is available.

The stack flow rate is calculated from the combustion turbine exhaust data provided from the manufacturer for operation in the "Power Augmentation Mode". The duct burner combustion air is solely provided by the combustion turbine exhaust. The contribution of stack exhaust from the components of natural gas combusted by the duct burner is negligible when compared to the large volume of exhaust from the combustion turbine.

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment _1_ of _1_

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (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 @ 1,000 Btu/scf*	5. Maximum Annual Rate: *16,714 x 10^6 scf @ 1,000 Btu/scf*
6. Estimated Annual Activity Factor: *Not Applicable*	
7. Maximum Percent Sulfur: *Negligible*	8. Maximum Percent Ash: *Negligible*
9. Million Btu per SCC Unit: *1,000 MMBtu/10^6 scf*	
10. Segment Comment (limit to 200 characters): *Several Source 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).*	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO	*0*	*030*	*NS*
NOX	*025*	*030*	*EL*
PM	*0*	*030*	*EL*
PM10	*0*	*030*	*EL*
SO2	*0*	*030*	*EL*
VOC	*0*	*030*	*NS*
HAP	*0*	*030*	*NS*
		Note: 030 is used for clean fuel firing.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *CO*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *52.5* lb/hour *216.4* tons/year *lb/hr based on PWR AUG @ 40°F, ton/year based on PWR AUG @ 68°F*
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year
6. Emission Factor: *0.0267 lb/MMBtu or 26.7 lb/10⁶ scf. nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for CO: 15 ppmv and 49.4 lb/hr at the "Power Augmentation Mode" @ 68°F (see item 3), and 1,847 MMBtu/hr heat input.* *Emission Factor Calculation for Long-term Emissions* *49.4 lb/hr / 1,847 MMBtu/hr = 0.0267 lb/MMBtu (26.7 lb/10⁶ scf. nat. gas)* *Annual Emissions Calculation* *49.4 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 216.4 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *General Electric emissions data at "Power Augmentation Mode", 1,847 MMBtu/hr heat input, and ambient air temperature of 68°F was used in long-term emissions calculations because operating under this mode is representative of annual operations while offering flexibility to operate with power augmentation mode.*

Allowable Emissions (Pollutant identified on front of page)

A.

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 216.4 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emissions factor of 0.0267 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the combustion turbine.*
4. Equivalent Allowable Emissions: *46.8* lb/hour *216.4* tons/year *lb/hr based on PWR AUG @ 40°F, ton/year based on PWR AUG @ 68°F*
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *During startup (~ 240 minutes) or shutdown periods (~ 180 minutes), and malfunctions it is requested that these periods not be included in the compliance evaluation.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *NOX*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *89.3* lb/hour *377.1* tons/year *lb/hr based on PWR AUG @ 40°F, ton/year based on PWR AUG @ 68°F*
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: *0.0466 lb/MMBtu or 46.6 lb/10⁶ scf nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for NO_x : 12 ppmv @ 15% O_2 and 86.1 lb/hr at the "Power Augmentation Mode" @ 68°F (see item 3), and 1,847 MMBtu/hr heat input.* *<u>Emission Factor Calculation for Long-term Emissions</u>* *86.1 lb/hr / 1,847 MMBtu/hr = 0.0466 lb/MMBtu (46.6 lb/10^6 scf. nat. gas)* *<u>Annual Emissions Calculation</u>* *86.1 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 377.1 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *General Electric emissions data at "Power Augmentation Mode", 1,847 MMBtu/hr heat input, and ambient air temperature of 68°F was used in long-term emissions calculations because operating under this mode is representative of annual operations while offering flexibility to operate with power augmentation mode.*

<u>Allowable Emissions</u> (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: *OTHER - BACT*
2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *12 ppmv @ 15% O_2 based on a thirty day rolling average and not to exceed 377.1 ton/yr based on a twelve month rolling total.*
4. Equivalent Allowable Emissions: *89.3* lb/hour *377.1* tons/year *lb/hr based on PWR AUG @ 40°F, ton/year based on PWR AUG @ 68°F*
5. Method of Compliance (limit to 60 characters): *NOX CEMS (CEMS are proposed to also be used in lieu of nitrogen fuel sampling.)*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *12 ppmv @ 15% O_2 is specified by the manufacturer for the "Power Augmentation Mode"@ 40°F and 68°F. Normal operation at or below 100% load is expected to be 9 ppmv @15 O_2., however, the higher ppmv value is proposed to allow for operational flexibility.* *This proposed emission restriction is more stringent than that required by 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-case load and ambient conditions.* *During startup (~ 240 minutes) or shutdown periods (~ 180 minutes), and malfunctions it is requested that these periods <u>not</u> be included in the compliance evaluation.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *PM*					
2. Total Percent Efficiency of Control:	*Not Applicable*	%			
3. Potential Emissions:	*9.5*	lb/hour	*41.6*	tons/year	
4. Synthetically Limited? [ ] Yes [X] No					
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year					
6. Emission Factor: *0.0051 lb/MMBtu or 5.1 lb/10^6 scf nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*					
7. Emissions Method Code:					
[ ] 0	[ ] 1	[ ] 2	[ ] 3	[ ] 4	[X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for PM: 9.5 lb/hr or less at all loads.* *<u>Emission Factor Calculation for Long-term Emissions</u>* *9.5 lb/hr / 1,847 MMBtu/hr = 0.0051 lb/MMBtu (5.1 lb/10^6 scf. nat. gas)* *<u>Annual Emissions Calculation</u>* *9.5 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 41.6 ton/yr*					
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *General Electric emissions data provides a maximum emission value for all modes of operation.*					

<u>Allowable Emissions</u> (Pollutant identified on front of page)

A.

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 41.6 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emissions factor of 0.0051 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the combustion turbine.*
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. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *During startup (~ 240 minutes) or shutdown periods (~ 180 minutes), and malfunctions it is requested that these periods <u>not</u> be included in the compliance evaluation. Good combustion practices will be used to maintain PM emissions at or below the equipment design emissions value specified in item 3 under Requested Allowable Emissions. The manufacturer guarantees 9.5 lb/hr or less for all operating modes.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *PM10*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *9.5* lb/hour *41.6* tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year
6. Emission Factor: *0.0051 lb/MMBtu or 5.1 lb/10^6 scf nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for PM_{10} : 9.5 lb/hr or less at all loads.* *Emission Factor Calculation for Long-term Emissions* *9.5 lb/hr / 1,847 MMBtu/hr = 0.0051 lb/MMBtu (5.1 lb/10^6 scf. nat. gas)* *Annual Emissions Calculation* *9.5 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 41.6 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *General Electric emissions data provides a maximum emission value for all modes of operation.*

Allowable Emissions (Pollutant identified on front of page)

A.

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 41.6 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emissions factor of 0.0051 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the combustion turbine.*
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. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *During startup (~ 240 minutes) or shutdown periods (~ 180 minutes), and malfunctions it is requested that these periods* ***not*** *be included in the compliance evaluation. Good combustion practices will be used to maintain* PM_{10} *emissions at or below the equipment design emissions value specified in item 3 under Requested Allowable Emissions. The manufacturer guarantees 9.5 lb/hr or less for all operating modes.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted:
SO2

2. Total Percent Efficiency of Control: *Not Applicable* %

3. Potential Emissions: *1.1* lb/hour *4.8* tons/year

4. Synthetically Limited?
[ ] Yes [X] No

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

6. Emission Factor: *0.0006 lb/MMBtu or 0.6 lb/10^6 scf nat. gas @ 1,000 Btu/scf*
Reference: *Manufacturer Data*

7. Emissions Method Code:
[ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5

8. Calculation of Emissions (limit to 600 characters):
Manufacturer Data for SO_2: 1.1 lb/hr at all loads based on 0.2 gr sulfur /100 scf nat. gas.

Emission Factor Calculation for Long-term Emissions
*0.002 gr/scf * lb/7,000 gr * 1,000 scf/MMBtu * 64.06 mol SO_2 / 32.06 mol S * 1,908 MMBtu/hr heat input PWR AUG @ 40°F (worst-case load) = 1.1 lb/hr*

1.1 lb/hr / 1,847 MMBtu/hr = 0.0006 lb/MMBtu (0.6 lb/10^6 scf. nat. gas)

Annual Emissions Calculation
*1.1 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 4.8 ton/yr*

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):
General Electric emissions data provides a maximum emission value for all modes of operation.

Allowable Emissions (Pollutant identified on front of page)

A.

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: *1.1* lb/hour *4.8* 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 proposed schedule (see Section 4.1.1.3 of the report text).*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (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.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *VOC*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *3.2* lb/hour *14.0* tons/year *lb/hr and ton/year based on PWR AUG 68°F*
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other 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: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for VOC: 1.4 ppmv and 3.2 lb/hr at the "Power Augmentation Mode"* *Emission Factor Calculation for Long-term Emissions* *3.2 lb/hr / 1,847 MMBtu/hr = 0.0017 lb/MMBtu (1.7 lb/10^6 scf. nat. gas)* *Annual Emissions Calculation* *3.2 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 14.0 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *General Electric emissions data at "Power Augmentation Mode", 1,847 MMBtu/hr heat input, and ambient air temperature of 68°F was used in long-term emissions calculations because operating under this mode is representative of annual operations while offering flexibility to operate with power augmentation mode.*

Allowable Emissions (Pollutant identified on front of page)

A.

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 14.0 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emissions factor of 0.0017 lb/MMBtu @ 1,000 Btu/scf Nat. Gas. fired in the combustion turbine.*
4. Equivalent Allowable Emissions: *3.2* lb/hour *14.0* tons/year
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (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. During startup (~ 240 minutes) or shutdown periods (~ 180 minutes), and malfunctions it is requested that these periods not be included in the compliance evaluation.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *HAP*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *0 (Trace)*lb/hour *0 (Trace)* tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year
6. Emission Factor: Reference: *No Data Available*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters):
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *Quality emissions information is not currently available for this type of unit.*

Allowable Emissions (Pollutant identified on front of page)
N/A

A.

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. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

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

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___2___

1. Visible Emissions Subtype: *VE20*
2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: *20* % *(6 min. avg.)* Exceptional Conditions: *27* % Maximum Period of Excess Opacity Allowed: *one period of 6* min/hour
4. Method of Compliance: *Initial compliance testing then annually when operating the duct burner and combustion turbine together [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: *VE20*
2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: *20* % *(6 min. avg.)* Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4. Method of Compliance: *Initial compliance testing then annually when operating the duct burner and combustion turbine together [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): *F.A.C. Rule 62-296.320 (4) (b) describes the VE requirements which is a general VE requirement for all sources where there is not another VE requirement in Chapter 62-296.*

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

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: *To be provided at a later date.* 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 40 CFR Part 60 Subpart Da (Duct Burner), Section 60.47a (c) and also by the Acid Rain rules of 40 CFR Part 72 and 75 for the combustion turbine..*	

Continuous Monitoring System: Continuous Monitor _____ of _____

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

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

   If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:				
PM	[ ] C	[ ] E	[X] Unknown	
SO2	[ ] C	[ ] E	[X] Unknown	
NO2	[ ] C	[ ] E	[X] Unknown	
4. Baseline Emissions:.				
PM	Unknown	lb/hour	Unknown	tons/year
SO2	Unknown	lb/hour	Unknown	tons/year
NO2			Unknown	tons/year
5. PSD Comment (limit to 200 characters): *The proposed cogeneration facility is a stand alone PSD project not involving netting with the host facility. The cogeneration facility is a major facility by PSD definition and will have potential increases in emissions of PM/PM_{10}, CO, VOC, and NO_x that are above the PSD significant threshold values and subjecting the facility and these pollutants to PSD preconstruction review.*				

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

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID:_*Fig 2-3*_ [ ] 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 Section 5 of the report text and appendices.*
4. Description of Stack Sampling Facilities [X] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested *Details will be provided at a later date as part of the stack testing and CEMs protocols.*
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 *Will be provided if requested at a later date.*
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable *Will be provided if requested at a later date.*
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [ ] Not Applicable *Additional information will be provided if requested as designs are finalized.*
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [ ] Not Applicable *Will be provided if requested.*

<u>Additional Supplemental Requirements for Category I Applications Only</u>

10. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
13. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
14. Acid Rain Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] 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:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L 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. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): *585 MMBtu/hr Natural Gas Fired Duct Burner located within the Heat Recovery Steam Generator (note: the duct burner's natural gas consumption will be limited to 3,280 x 10^6 scf.)*		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown *HRSG-0001*		
3. Emissions Unit Status Code: *C*	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: *49*
6. Emissions Unit Comment (limit to 500 characters): *The duct burner will be a Coen or equivalent with a rated heat input of 585 MMBtu/hr. The duct burner will incorporate a low NO_x burner. The duct burner will fire natural gas only. The duct burner is used to supply additional heat to the combustion turbine exhaust in the heat recovery steam generator (HRSG) in order to meet the steam demands for the host facility. The combustion air for the duct burner will primarily be provided by the combustion turbine exhaust. Please see Section 2 of the report text for additional information.*		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): *Low NO_x Burner is an integral part of the duct burner design.*
2. Control Device or Method Code: *025*

B.

1. Description (limit to 200 characters): *Clean fuel (natural gas) will be combusted in the duct burner. Code 030 is the closest match for low sulfur fuel also.*
2. Control Device or Method Code: *030*

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: *Approximately 5 months after approval and start of construction.*	
2. Long-term Reserve Shutdown Date: *Not Applicable*	
3. Package Unit: *Duct Burner* Manufacturer: *Coen or equivalent*	Model Number: *Not Available*
4. Generator Nameplate Rating: MW *Note: The steam electric turbine associated with the HSRG will be less than 75 MWe.*	
5. Incinerator Information: *Not Applicable* Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F	

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate: *585*	mmBtu/hr
2. Maximum Incineration Rate: lb/hr *Not Applicable*	tons/day
3. Maximum Process or Throughput Rate: *Not Applicable*	
4. Maximum Production Rate: *400,000 lb steam/ hour (based on 85% heat transfer efficiency)*	
5. Operating Capacity Comment (limit to 200 characters): *The duct burner has a design heat input capacity of 585 MMBtu/hr. Santa Rosa Energy LLC requests that annual natural gas usage be limited to 3,280 x 10^6 scf.*	

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:			
24	hours/day	*7*	days/week
52	weeks/year	*8,760*	hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable, The Facility is a Title V source.

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

Chapter 62-204, Rule 62-204.240 (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 air 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 Da (60.40a through 60.49a)	*Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978 (Applicable to Duct Burner Only)*
40 CFR 60.42a (a)	*Particulate matter emissions cannot exceed 0.03 lb/MMBtu.*
40 CFR 60.42a (b)	*Opacity cannot exceed 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent.*
40 CFR 60.43a (b)(2)	*SO_2 emissions cannot exceed 0.20 lb/MMBtu*
40 CFR 60.44a	*NO_x emissions cannot exceed 0.20 lb/MMBtu for gaseous fuels.*
40 CFR 60.46a	*Compliance is required for the particulate matter, SO_2 and NO_x standards except during start-up, shutdown, or malfunction.*
40 CFR 60.47a	*CEMS are required for NO_x and either O_2 or CO_2.*
40 CFR 60.48a	*Performance Testing Requirements*
40 CFR 60.49a	*Reporting Requirements*
See Section 4 of the report text for additional information.	

E. 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 [X] 2 [ ] 3 [ ] 4

3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):
The natural gas fired duct burner's combustion air is the exhaust gas from the natural gas fired combustion turbine.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
GT-0001 and HRSG-0001

5. Discharge Type Code:
[ ] D [ ] F [ ] H [ ] P
[ ] R [X] V [ ] W

6. Stack Height:	*Appr. 200* feet
7. Exit Diameter:	*Appr. 19* feet
8. Exit Temperature:	*Appr. 196 - 216* °F

9. Actual Volumetric Flow Rate: *See Comments*	*1,073,024* acfm
10. Percent Water Vapor :	*Approximately 10* %
11. Maximum Dry Standard Flow Rate:	*786,183* dscfm
12. Nonstack Emission Point Height: *Not Applicable*	feet
13. Emission Point UTM Coordinates: Zone: *16* East (km): *488.970*	North (km): *3,381.350*

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

Stack diameter calculated assuming an average exhaust velocity (60 fps at 100% load, 40°F). Actual stack diameter to be provided when final design information is available.

The stack flow rate is calculated from the combustion turbine exhaust data provided from the manufacturer for operation in the "Power Augmentation Mode". The duct burner combustion air is solely provided by the combustion turbine exhaust. The contribution of stack exhaust from the components of natural gas combusted by the duct burner is negligible when compared to the exhaust from the combustion turbine.

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment __1__ of __1__

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): *Natural Gas Combustion for the Duct Burner.*	
2. Source Classification Code (SCC): *1-01-006-01 External Combustion Boiler, Electric Generation, Natural Gas*	
3. SCC Units: *Million Cubic Feet Burned*	
4. Maximum Hourly Rate: *0.585 x 10^6 scf @ 1,000 Btu/scf*	5. Maximum Annual Rate: *3,280 x 10^6 scf @ 1,000 Btu/scf*
6. Estimated Annual Activity Factor: *Not Applicable*	
7. Maximum Percent Sulfur: *Negligible*	8. Maximum Percent Ash: *Negligible*
9. Million Btu per SCC Unit: *1,000 MMBtu/10^6 scf*	
10. Segment Comment (limit to 200 characters): *The SCC chosen is the same as that used for US EPA AP-42 5th. ed. Section 1.4. (Note: vendor emissions information was used in calculations for all emissions estimates rather that values present in Section 1.4 of AP-42.)*	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO	*0*	*030*	*NS*
NOX	*025*	*030*	*EL*
PM	*0*	*030*	*EL*
PM10	*0*	*030*	*EL*
SO2	*0*	*030*	*EL*
VOC	*0*	*030*	*NS*
HAP	*0*	*030*	*NS*
	Note: 025 is used for low NO_x burner.	*Note: 030 is used for clean fuel firing.*	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *CO*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *46.8* lb/hour *131.2* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
4. Synthetically Limited? [X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year
6. Emission Factor: *0.08 lb/MMBtu or 80 lb/10^6 scf. nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for CO: 0.08 lb/MMBtu* *<u>Emission Factor Calculation</u>* *0.08 lb/MMBtu * MMBtu/1,000,000 Btu * 1,000 Btu/scf nat. gas * 1,000,000 scf/(10^6 scf) = 80 lb/10^6 scf. nat. gas* *<u>Annual Emissions Calculation</u>* *80.0 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 131.2 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *Annual emissions are based on a natural gas limit of 3,280 x 10^6 scf. Emission factors are for Coen (or equivalent) low NOX burner.*

Allowable Emissions (Pollutant identified on front of page)

A.

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 131.2 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emission factor of 0.08 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the duct burner.*
4. Equivalent Allowable Emissions: *46.8* lb/hour *131.2* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *During startup (~ 240 minutes) or shutdown periods (~180 minutes), and malfunction it is requested that these periods not be included in the compliance evaluation.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *NOX*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *46.8* lb/hour *131.2* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
4. Synthetically Limited? [X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: *0.08 lb/MMBtu or 80 lb/10^6 scf. nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for NOX: 0.08 lb/MMBtu* *Emission Factor Calculation* *0.08 lb/MMBtu * MMBtu/1,000,000 Btu * 1,000 Btu/scf nat. gas * 1,000,000 scf/(10^6 scf) = 80 lb/10^6 scf. nat. gas* *Annual Emissions Calculation* *80.0 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 131.2 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *Annual emissions are based on a natural gas limit of 3,280 x 10^6 scf. Emission factors are for Coen (or equivalent) low NOX burner.*

Allowable Emissions (Pollutant identified on front of page)

A.

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 131.2 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emission factor of 0.08 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the duct burner.*
4. Equivalent Allowable Emissions: *46.8* lb/hour *131.2* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
5. Method of Compliance (limit to 60 characters): *NOX CEMS*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *0.08 lb/MMBtu is guaranteed by the manufacturer.* *This emission restriction is more stringent than that required by 40 CFR Part 60, Subpart Da, Section 60.44a which is 0.20 lb/MMBtu.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *PM*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *4.7* lb/hour *13.1* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit..*
4. Synthetically Limited? [X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year
6. Emission Factor: *0.008 lb/MMBtu or 8.0 lb/10^6 scf nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for PM: 0.008 lb/MMBtu* *<u>Emission Factor Calculation</u>* *0.008 lb/MMBtu * MMBtu/1,000,000 Btu * 1,000 Btu/scf nat. gas * 1,000,000 scf/(10^6 scf) = 8.0 lb/10^6 scf. nat. gas* *<u>Annual Emissions Calculation</u>* *8.0 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 13.1 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *Annual emissions are based on a natural gas limit of 3,280 x 10^6 scf. Emission factors are for Coen (or equivalent) low NOX burner.*

Allowable Emissions (Pollutant identified on front of page)

A.

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 13.1 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emission factor of 0.008 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the duct burner.*
4. Equivalent Allowable Emissions: *4.7* lb/hour *13.1* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit..*
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *0.008 lb/MMBtu is guaranteed by the manufacturer.* *This emission restriction is more stringent than that required by 40 CFR Part 60, Subpart Da, Section 60.42a which is 0.03 lb/MMBtu. This limit is also more stringent than F.A.C. Chapter 62-296, Rule 62-296.405 (1)(b) which is 0.1 lb/MMBtu.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted:
PM10

2. Total Percent Efficiency of Control: *Not Applicable* %

3. Potential Emissions: *4.7* lb/hour *13.1* tons/year
Annual emissions based on 3,280 x 10^6 scf fuel limit.

4. Synthetically Limited?
[X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*

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

6. Emission Factor: *0.008 lb/MMBtu or 8.0 lb/10^6 scf nat. gas @ 1,000 Btu/scf*
Reference: *Manufacturer Data*

7. Emissions Method Code:
[ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5

8. Calculation of Emissions (limit to 600 characters):
Manufacturer Data for PM10: 0.008 lb/MMBtu
Emission Factor Calculation

*0.008 lb/MMBtu * MMBtu/1,000,000 Btu * 1,000 Btu/scf nat. gas * 1,000,000 scf/(10^6 scf) = 8.0 lb/10^6 scf. nat. gas*

Annual Emissions Calculation
*8.0 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 13.1 ton/yr*

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):
Annual emissions are based on a natural gas limit of 3,280 x 10^6 scf. Emission factors are for Coen (or equivalent) low NOX burner.

Allowable Emissions (Pollutant identified on front of page)

A.

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 13.1 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emission factor of 0.008 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the duct burner.*
4. Equivalent Allowable Emissions: *4.7* lb/hour *13.1* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *0.008 lb/MMBtu is guaranteed by the manufacturer.* *This emission restriction is more stringent than that required by 40 CFR Part 60, Subpart Da, Section 60.42a which is 0.03 lb/MMBtu. This limit is also more stringent than F.A.C. Chapter 62-296, Rule 62-296.405 (1)(b) which is 0.1 lb/MMBtu.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *SO2*
2. Total Percent Efficiency of Control: *Not Applicable* %
3. Potential Emissions: *0.59* lb/hour *1.6* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit..*
4. Synthetically Limited? [X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: *0.001 lb/MMBtu or 1.0 lb/10^6 scf nat. gas @ 1,000 Btu/scf* Reference: *Manufacturer Data*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5
8. Calculation of Emissions (limit to 600 characters): *Manufacturer Data for SO2: 0.001 lb/MMBtu* *Emission Factor Calculation* *0.001 lb/MMBtu * MMBtu/1,000,000 Btu * 1,000 Btu/scf nat. gas * 1,000,000 scf/(10^6 scf) = 1.0 lb/10^6 scf. nat. gas* *Annual Emissions Calculation* *1.0 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 1.6 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *Annual emissions are based on a natural gas limit of 3,280 x 10^6 scf. Emission factors are for Coen (or equivalent) low NOX burner.*

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: *ESCPSD*
2. Future Effective Date of Allowable Emissions: *Not Applicable*
3. Requested Allowable Emissions and Units: *Not to exceed 1.6 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emission factor of 0.001 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the duct burner.*
4. Equivalent Allowable Emissions: *0.59* lb/hour *1.6* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
5. Method of Compliance (limit to 60 characters): *Compliance will be assured by only using natural gas to fire the duct burner.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): *The emission restriction per 40 CFR Part 60, Subpart Da, Section 60.43a(b)(2) is 0.20 lb/MMBtu. Only natural gas will be fired in the gas combustion turbine and the SO2 emissions will be much less than 0.20 lb/MMBtu and 40 tpy, the PSD threshold.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted:
VOC

2. Total Percent Efficiency of Control: *Not Applicable* %

3. Potential Emissions: *11.1* lb/hour *31.2* tons/year
Annual emissions based on 3,280 x 10^6 scf fuel limit.

4. Synthetically Limited?
[X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*

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

6. Emission Factor: *0.019 lb/MMBtu or 19.0 lb/10^6 scf nat. gas @ 1,000 Btu/scf*
Reference: *Manufacturer Data*

7. Emissions Method Code:
[ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5

8. Calculation of Emissions (limit to 600 characters):
Manufacturer Data for VOC: 0.019 lb/MMBtu
Emission Factor Calculation

*0.019 lb/MMBtu * MMBtu/1,000,000 Btu * 1,000 Btu/scf nat. gas * 1,000,000 scf/(10^6 scf) = 19.0 lb/10^6 scf nat. gas*

Annual Emissions Calculation
*19.0 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 31.2 ton/yr*

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):
Annual emissions are based on a natural gas limit of 3,280 x 10^6 scf. Emission factors are for Coen (or equivalent) low NOX burner.

Allowable Emissions (Pollutant identified on front of page)

A.

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 31.2 ton/yr based on a 12 month rolling total. Emissions will be calculated monthly based on an emission factor of 0.019 lb/MMBtu @ 1,000 Btu/scf Nat. Gas fired in the duct burner.*
4. Equivalent Allowable Emissions: *11.1* lb/hour *31.2* tons/year *Annual emissions based on 3,280 x 10^6 scf fuel limit.*
5. Method of Compliance (limit to 60 characters): *Good combustion practices along with recordkeeping of fuel usage.*
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (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. During startup (~ 240 minutes) or shutdown periods (~ 180 minutes) it is requested that the above allowable emissions limits not apply.*

B.

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted:
HAP

2. Total Percent Efficiency of Control: *0* %

3. Potential Emissions: *1.1* lb/hour *3.10* tons/year

4. Synthetically Limited?
[X] Yes [ ] No
Annual natural gas usage limited to 3,280 x 10^6 scf.

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

6. Emission Factor: *0.00189 lb/MMBtu or 1.89 lb/10^6 scf nat. gas @ 1,000 Btu/scf*
Reference: *US EPA AP-42 5th ed Supplement D*

7. Emissions Method Code:
[ ] 0 [ ] 1 [ ] 2 [ ] 3 [X] 4 [ ] 5
High excess air for the duct burner is not typical for AP-42 boiler based factors.

8. Calculation of Emissions (limit to 600 characters):
AP -42 factors for HAPs: 0.00189 lb/MMBtu

Emissions Factor Calculation
See Appendix B, Table B-1 of the Report Text

Annual Emissions Calculation

*1.89 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 3.10 ton/yr*

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):
HAPs were determined from US EPA AP-42 emissions factors for natural gas combustion (Boilers). Species of organic and inorganic values were reviewed to determine HAP species. All HAPs are considered either as VOC or particulate matter for fee purposes.

Allowable Emissions (Pollutant identified on front of page)

A.

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. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

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

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __2__

1. Visible Emissions Subtype: *VE20*
2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: *20* % *(6 min. avg.)* Exceptional Conditions: *27* % Maximum Period of Excess Opacity Allowed: *one period of 6* min/hour
4. Method of Compliance: *Initial compliance testing then annually when operating the duct burner and combustion turbine together [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: *VE20*
2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: *20* % *(6 min. avg.)* Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4. Method of Compliance: *Initial compliance testing then annually when operating the duct burner and combustion turbine together [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): *F.A.C. Rule 62-296.320 (4) (b) describes the VE requirements which is a general VE requirement for all sources where there is not another VE requirement in Chapter 62-296.*

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

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: *To be provided at a later date.* 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 40 CFR Part 60 Subpart Da, Section 60.47a (c) and also by the Acid Rain rules of 40 CFR Part 72 and 75 for the combustion turbine..*	

Continuous Monitoring System: Continuous Monitor _____ of _____

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

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

   If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:				
PM	[ ] C	[ ] E	[X] Unknown	
SO2	[ ] C	[ ] E	[X] Unknown	
NO2	[ ] C	[ ] E	[X] Unknown	
4. Baseline Emissions:				
PM	Unknown	lb/hour	Unknown	tons/year
SO2	Unknown	lb/hour	Unknown	tons/year
NO2			Unknown	tons/year

5. PSD Comment (limit to 200 characters):

The proposed cogeneration facility is a stand alone PSD project not involving netting with the host facility. The cogeneration facility is a major facility by PSD definition and will have potential increases in emissions of PM/PM_{10}, CO, VOC, and NO_x that are above the PSD significant threshold values and subjecting the facility and these pollutants to PSD preconstruction review.

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

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID:_*Fig 2-3*_ [ ] 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 Section 5 of the report text and appendices.*
4. Description of Stack Sampling Facilities [X] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested *Details will be provided at a later date as part of the stack testing and CEMs protocols.*
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 *Will be provided if requested at a later date.*
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable *Will be provided if requested at a later date.*
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [ ] Not Applicable *Additional information will be provided if requested as designs are finalized.*
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [ ] Not Applicable *Will be provided if requested.*

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
13. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
14. Acid Rain Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] 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:________ [ ] Not Applicable

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: *HAP*
2. Total Percent Efficiency of Control: *0* %
3. Potential Emissions: *1.1* lb/hour *3.10* tons/year
4. Synthetically Limited? [X] Yes [ ] No *Annual natural gas usage limited to 3,280 x 10^6 scf.*
5. Range of Estimated Fugitive/Other Emissions: *Not Applicable* [ ] 1 [ ] 2 [ ] 3 _______ to _______ tons/year
6. Emission Factor: *0.00189 lb/MMBtu or 1.89 lb/10^6 scf nat. gas @ 1,000 Btu/scf* Reference: *US EPA AP-42 5th ed Supplement D*
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [X] 4 [ ] 5 *High excess air for the duct burner is not typical for AP-42 boiler based factors.*
8. Calculation of Emissions (limit to 600 characters): *AP -42 factors for HAPs: 0.00189 lb/MMBtu* *Emissions Factor Calculation* *See Appendix B, Table B-1 of the Report Text* *Annual Emissions Calculation* *1.89 lb/10^6 scf * 3,280 x 10^6 scf / 2,000 lb/ton = 3.10 ton/yr*
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): *HAPs were determined from US EPA AP-42 emissions factors for natural gas combustion (Boilers). Species of organic and inorganic values were reviewed to determine HAP species. All HAPs are considered either as VOC or particulate matter for fee purposes.*

<u>**Allowable Emissions**</u> (Pollutant identified on front of page)

A.

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. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

B.

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

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___2___

1. Visible Emissions Subtype: *VE20*
2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: *20* % *(6 min. avg.)* Exceptional Conditions: *27* % Maximum Period of Excess Opacity Allowed: *one period of 6* min/hour
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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___

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5. Visible Emissions Comment (limit to 200 characters): *F.A.C. Rule 62-296.320 (4) (b) describes the VE requirements which is a general VE requirement for all sources where there is not another VE requirement in Chapter 62-296.*

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

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: *To be provided at a later date.* 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 40 CFR Part 60 Subpart Da, Section 60.47a (c) and also by the Acid Rain rules of 40 CFR Part 72 and 75 for the combustion turbine..*	

Continuous Monitoring System: Continuous Monitor _____ of _____

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3. CMS Requirement:	[ ] Rule [ ] Other
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6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

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   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

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[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

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3. Increment Consuming/Expanding Code:				
PM	[ ] C	[ ] E	[X] Unknown	
SO2	[ ] C	[ ] E	[X] Unknown	
NO2	[ ] C	[ ] E	[X] Unknown	
4. Baseline Emissions:				
PM	Unknown	lb/hour	Unknown	tons/year
SO2	Unknown	lb/hour	Unknown	tons/year
NO2			Unknown	tons/year

5. PSD Comment (limit to 200 characters):

The proposed cogeneration facility is a stand alone PSD project not involving netting with the host facility. The cogeneration facility is a major facility by PSD definition and will have potential increases in emissions of PM/PM_{10}, CO, VOC, and NO_x that are above the PSD significant threshold values and subjecting the facility and these pollutants to PSD preconstruction review.

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

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID:_*Fig 2-3*_ [ ] 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 Section 5 of the report text and appendices.*
4. Description of Stack Sampling Facilities [X] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested *Details will be provided at a later date as part of the stack testing and CEMs protocols.*
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 *Will be provided if requested at a later date.*
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable *Will be provided if requested at a later date.*
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [ ] Not Applicable *Additional information will be provided if requested as designs are finalized.*
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [ ] Not Applicable *Will be provided if requested.*

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
13. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
14. Acid Rain Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] 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:________ [ ] Not Applicable

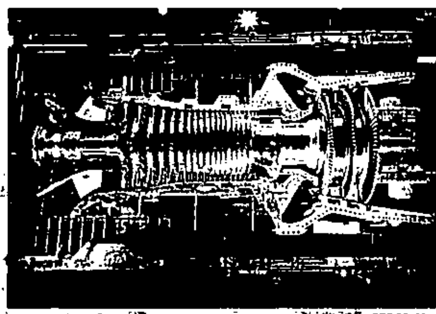
APPENDIX D
VENDOR INFORMATION

GE Gas Turbines

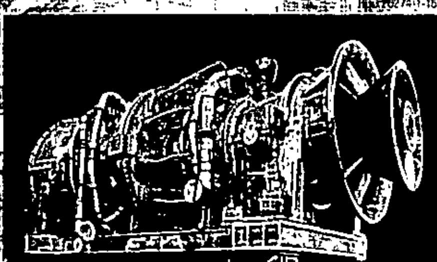
The Power Plant for the Next Century is Here Today.

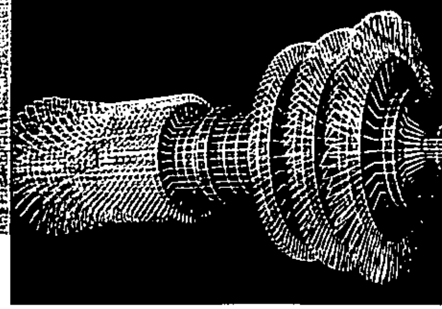
MS7001FA

MS7001FA
MS7001FA
MS7001FA



RDC 26493-1





RDC 26338-9

MS7001FA
MS7001FA

The 7FA. Power For A New World, A New Century.

The new standard for reliability, availability and maintainability in advanced gas turbines for utilities and industry.

The prime mover for power plants of the next century is the GE MS7001FA – the 7FA – the most powerful 60 Hz combustion turbine in the world.

The 7FA was developed to meet the needs power producers will face in the 1990s and beyond. Designed for optimum reliability and efficiency with low maintenance, it is highly flexible in cycle configuration, fuel conversion and site adaptation.

GE "F" technology is well-proven. The 7FA was derived from GE's highly successful MS7001EA, which, with nearly 600 units operating dependably around the world, is the established workhorse of the 60 Hz power generation marketplace. The 7FA shares significant construction features, materials and aerodynamic similarities with the 7EA while possessing the same design-life requirements responsible for the outstanding reliability of that product.

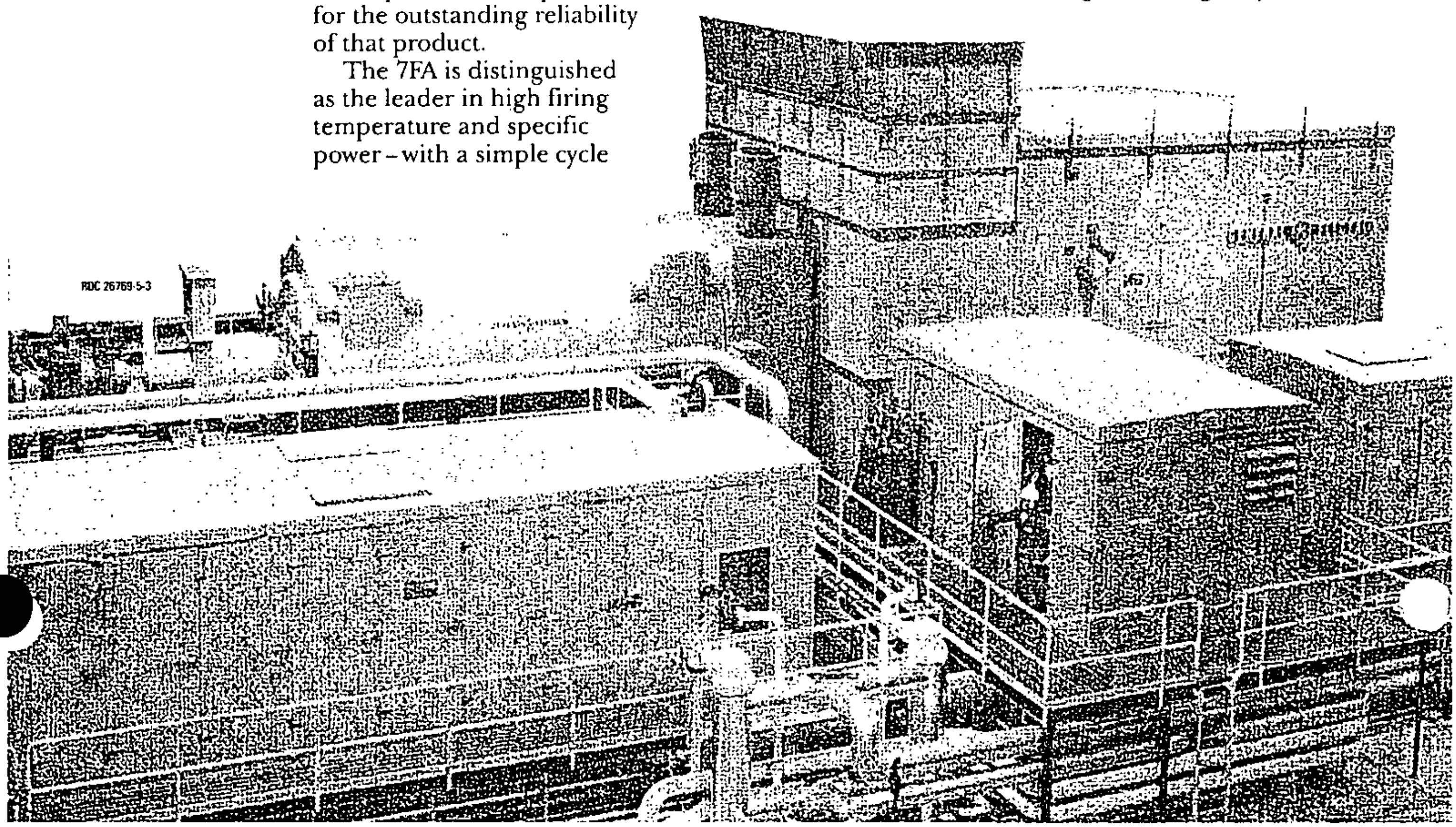
The 7FA is distinguished as the leader in high firing temperature and specific power – with a simple cycle rating of 159 MW. It is the industry's only turbine offering commercial operation at 2350° F (1288° C) firing temperature. The corresponding "F" class exhaust temperature and system flexibility contribute to the unit's unmatched performance in combined cycle applications; it can produce 241 MW in combined cycle applications, and up to 265 MW in integrated gasification combined cycle plants (IGCC).

And the future is in place: over 75% of advanced, high firing temperature gas turbines on order or in operation worldwide are GE design.

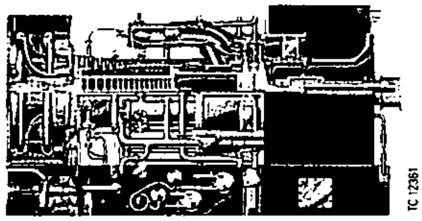
The new 7FA is a classic example of GE evolutionary design in action. The result is a family of gas turbines whose performance and efficiency have been progressively improved over the years, so that each new design retains the proven reliability of its predecessors.

In selecting the 7FA for your capacity requirements, you can move ahead with confidence. Your 7FA unit is preceded by 200 million fired hours of GE experience, gained from four times the installed base of GE's nearest competitor. You will also benefit from advances derived from GE aircraft engine development, from GE's Research and Development Center, and from the delivery capacity of the world's largest and most advanced gas turbine production facilities.

Growing energy needs in the coming century call for new and better ways to produce power. GE gas turbine technology is readily available everywhere. It is ready to begin working for you now.

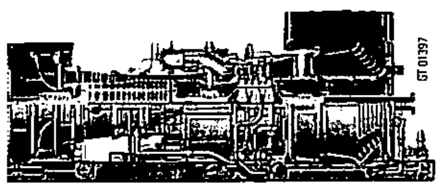


GE Gas Turbine Technology. Proven Design.

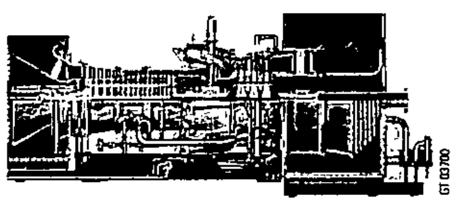


GE MS5001P gas turbine is rated at 26.3 MW. The MS5000 series is the most widely used gas turbine in the world. Experience with over 2,000 units – for power production, process and pipeline drives and transportation – again proved the effectiveness of evolutionary new designs that led to ever-larger output.

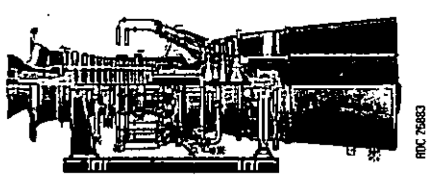
GE MS6001B gas turbine, rated 38.3 MW, is available for both 50 and 60 Hz service. The MS6001 (6B) was derived from the successful MS7001 series of GE machines. Nearly 400 are currently in operation; many used for cogeneration, others for industrial and utility power needs. The newest application of the Frame 6 is for compressor drive in gas injection and LNG plants – rated at 50,010 hp.



GE MS7001EA series 60 Hz gas turbine is base-rated at 83.5 MW. Nearly 600 units are generating power for utilities and industries around the world. Design and performance concepts proven in the 7EA led to geometrically scaling-up the machine for the MS9000E series. The Frame 7 is also available as a compressor drive and is rated 108,200 hp.

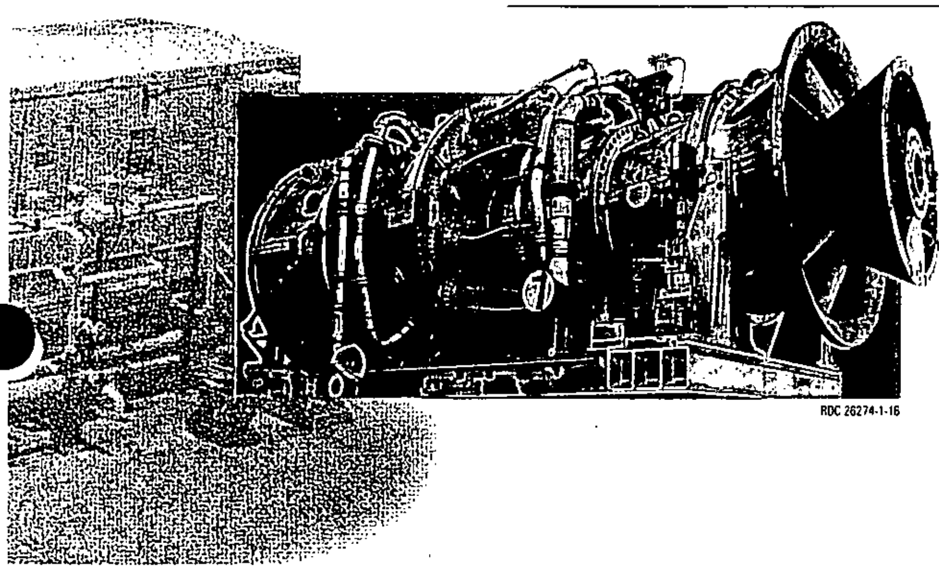


GE MS9001E series is a 3,000 rpm, 123.4 MW scaled version of the MS7001E, designed for 50 Hz generation service. It incorporates aeroderived cooling designs and materials for longer unit life at higher cycle temperatures with greater fuel efficiency. Current operational experience exceeds 1 million fired hours.



GE MS9001FA series is the largest gas turbine ever made. It is a scaled-up version of the MS7001FA for 50 Hz application. The first commercial 9F unit was put into service in 1992 at Electricité de France for power generation near Paris. Rated at 226.5 MW in simple cycle, it can produce 348.5 MW in combined cycle and up to 380 MW in IGCC.

Virginia Power's Chesterfield Station Unit #8 features a GE STAG™ 107F combined cycle unit. This is the second 7F unit added by the utility, repowering a conventional coal-fired site. By repowering with these advanced units, Virginia Power added nearly four times the power and twice the fuel efficiency of the previous power plant – with lower emissions.



GE MS7001FA series is the advanced technology power giant of the 60 Hz market, rated at 159 MW with a firing temperature of 2350° F (1288° C) at 3600 rpm. In commercial operation the 7F has consistently maintained reliability levels of nearly 99%; multiple orders demonstrate its favor among the world's leading 60 Hz utilities.

7FA Flexibility. The Power To Meet Changing Needs.

The MS7001FA gas turbine now makes it easier for you to supply the large blocks of power that will be needed in the coming century. The 7FA can bring power on-line quickly, while offering fuel flexibility, high efficiency and low capital cost. And, it all comes in a compact package.

The 7FA provides the widest range of choice to match your needs. It is adaptable to simple cycle and single- or multi-shaft combined cycle applications. You also gain a wide choice of fuels – thus the ability to change over as needed for natural gas, oil and coal-derived gas.

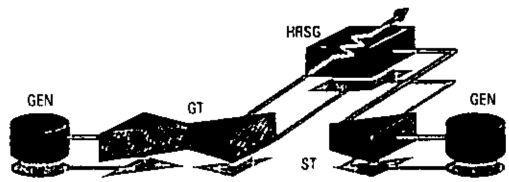
Originally, GE gas turbines were applied primarily for peaking duty service by virtue of their high starting reliability and quick load capability. Today, F technology units are also the preferred choice in combined cycle configurations for mid-range and baseload duty. Compared to earlier MS7001 gas turbines, the 7FA offers 80% greater output, with a combined cycle efficiency reaching 55%. The 7FA is particularly well-adapted to large power stations, where plant efficiency and longer operating hours are critical. GE design engineers have placed special emphasis on starting and operating reliability of the 7FA, as well as on maintainability.

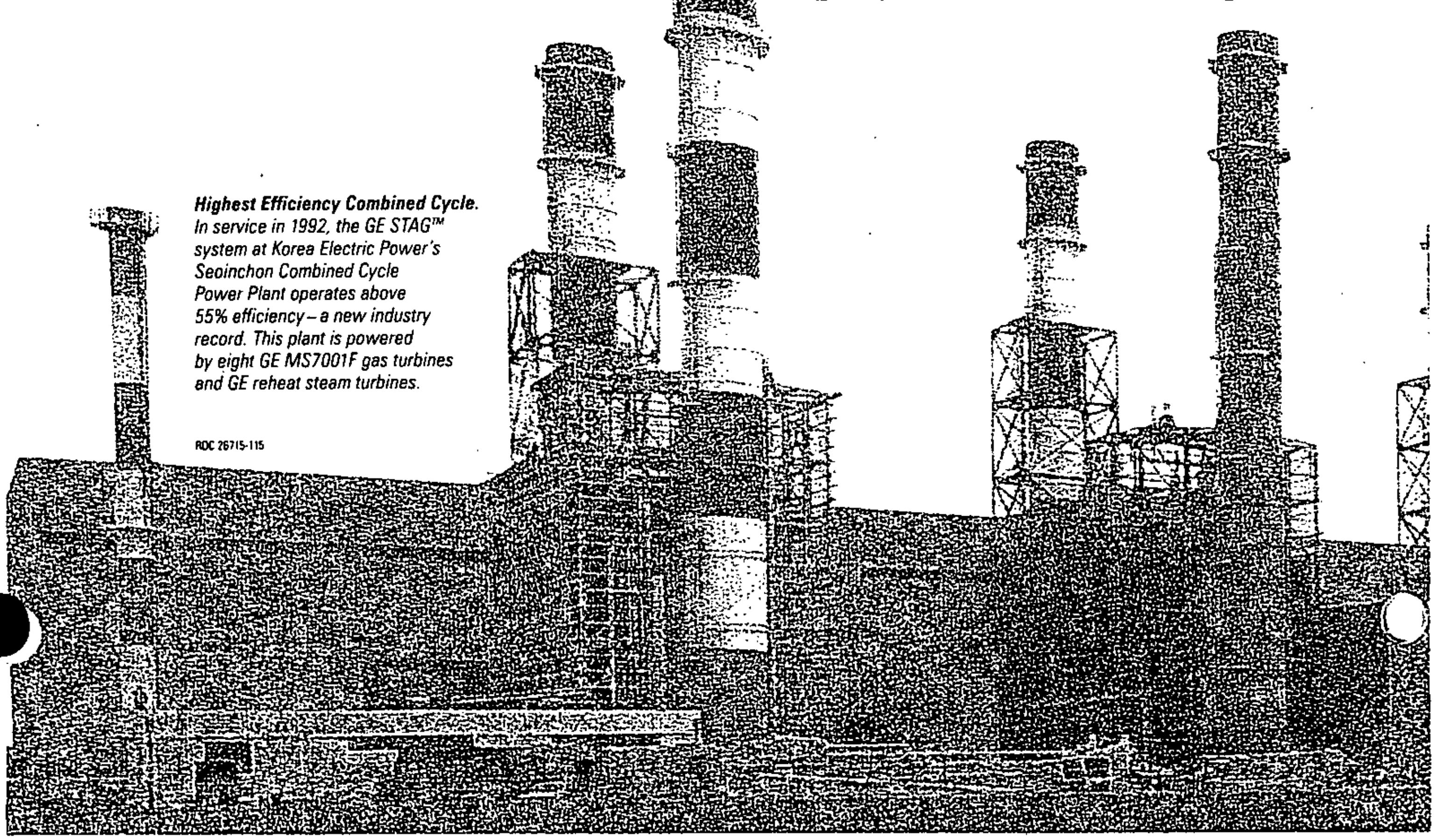
Most important, the MS7001FA represents the latest generation of machines that have proven themselves in successful applications all over the world. All GE F technology gas turbines benefit from experience gained with almost 5,000 units – over half the world's heavy-duty and aeroderivative machines.

More and more, these advanced GE gas turbines are providing the answer to world power producers who must take action now to meet future demands.

Simple cycle.
In simple cycle applications using natural gas as fuel, the 7FA is nominally rated at 159 MW at 35% efficiency. For peaking applications, F technology units can be brought on-line quickly, providing large, cost-effective blocks of power.

Combined cycle.
In combined cycle operation burning natural gas, 7FA gas turbine output reaches 241 MW. Its high exhaust temperature allows a reheat steam cycle, enabling total plant efficiencies in excess of 55%. The 7FA can provide major fuel savings in baseload combined cycle operation and is adaptable to either single-shaft or multi-shaft configuration.





Highest Efficiency Combined Cycle.
In service in 1992, the GE STAG™ system at Korea Electric Power's Seoinchon Combined Cycle Power Plant operates above 55% efficiency – a new industry record. This plant is powered by eight GE MS7001F gas turbines and GE reheat steam turbines.

RDC 26715-115

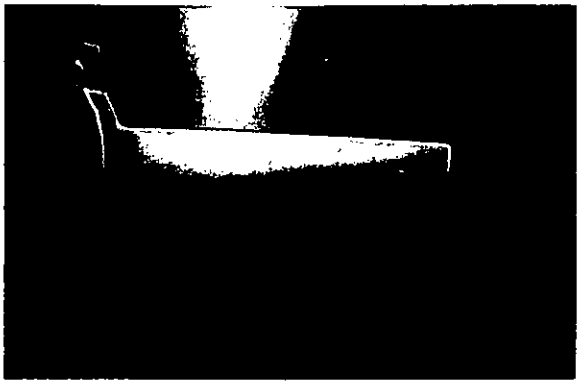
GE Technology. The World's Power Source.

The great leap in capacity and performance that F technology machines offer to power producers is the result of GE's 10-year development program.

First, we drew upon our unique experience as the world's leader in aircraft engines to bring the most advanced high-temperature and cooling technologies down to earth. GE's Corporate Research & Development Center contributed new metallurgical materials and manufacturing techniques.

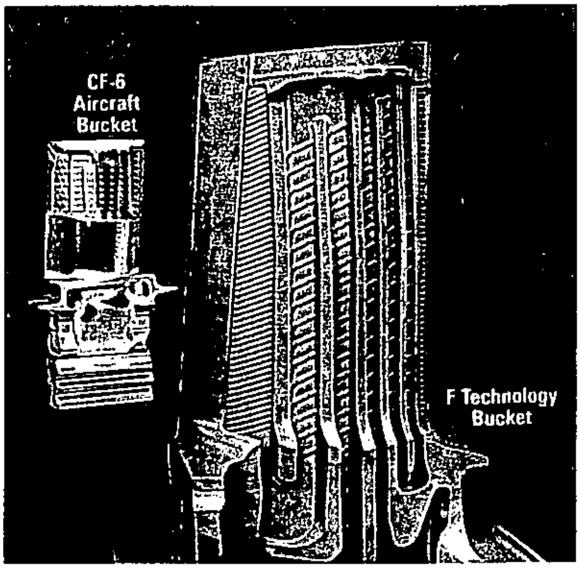
These advances were then incorporated into the already proven designs of GE's heavy-duty gas turbine line to create an entirely new generation of combustion turbine: the F technology machines. Both factory testing and operational experience have indicated that the 7FA is as reliable as its GE predecessors.

Because of GE's evolutionary design philosophy, much of this rapidly advancing technology is readily adaptable to GE's installed turbine fleet – the world's largest. This is all part of a continuing process to make our proven, high-performance machines even better. An investment in a GE 7FA means getting optimum performance over the life of the machine.



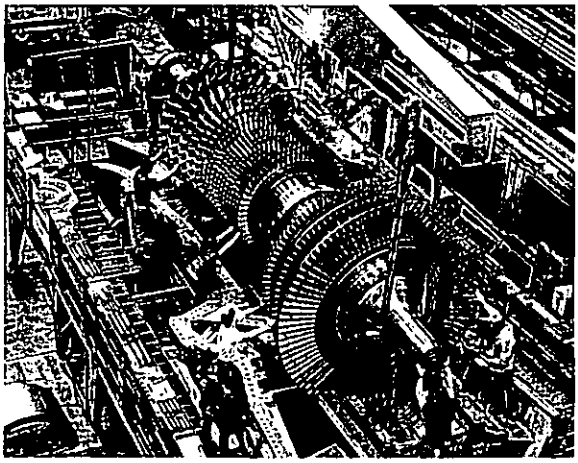
RDC 26754-73

R&D: Improving The Basics.
GE's proprietary Plasma-Guard GT-29 In-Plus™ powdered metal alloy is used to enhance the corrosion and oxidation resistance of the 7FA's first and second stage buckets. Recognized as one of the most advanced technologies in the world, the Vacuum Plasma Spray process developed by GE uses a 20,000° F (11,000° C) plasma torch to apply a clean, dense, uniform coating on the exterior of the buckets. This yields a superior hot corrosion resistance which multiplies the corrosion life of various hot gas path components – one key to greater gas turbine efficiency and reliability. New GE super alloys, such as the patented GTD-222, allow gas turbines to operate at much higher temperatures and efficiencies. Now under development: single crystal technology that will totally eliminate grain boundaries in material. This will improve impact resistance, creep life and low cycle fatigue resistance.



RDC 26706-14-7

Aeroderivative Technology: Borrowing From The Best.
The firing temperature of GE FA units – 2350° F (1288° C) – is the highest in the power generation industry. To accommodate this increased firing temperature, the FA employs advanced cooling techniques developed by GE Aircraft Engines. The first and second stage buckets as well as all three nozzle stages are air-cooled. The first stage bucket is convectively cooled by means of an advanced aircraft-derived serpentine arrangement. Cooling air exits through axial airways located on the bucket's trailing edge and tip, and also through leading edge and side walls for film cooling.



RDC 26454-11-5

FA Manufacturing: Committed To Quality.
GE manufacturing employs the most advanced techniques, developed at the world's largest gas turbine factory – located in the USA in Greenville, South Carolina. For example:

- *The "moment weighing" technique determines each gas turbine bucket's center of gravity and optimal wheel position. Rotor balancing is accomplished in the factory, not at the customer's site. A replacement bucket, if needed, is built to your unit's precise reference specifications which are accessed from GE's database. This then enables flawless bucket replacement and rebalancing in the field.*

GE's industry leading manufacturing techniques are shared with our manufacturing associates worldwide, ensuring top quality around the globe. The recent expansion of the Greenville plant to 1 million square feet (92,900 square meters) along with GE business associate plant resources totalling 6.5 million square feet (600,000 square meters) endow GE with manufacturing capacity unequalled in the industry.

GE F Technology. The Future Is In Place.

The 60 Hz power maker for the next century is available today – the MS7001FA from GE.

With technology that has proven design, evolved from an experience base of over 200 million gas turbine fired hours – four times the installed base of our nearest competitor.

With technology that has proven worldwide application and acceptance. Over 75% of advanced gas turbines on order or in operation are GE F technology machines, designated for a variety of configurations.

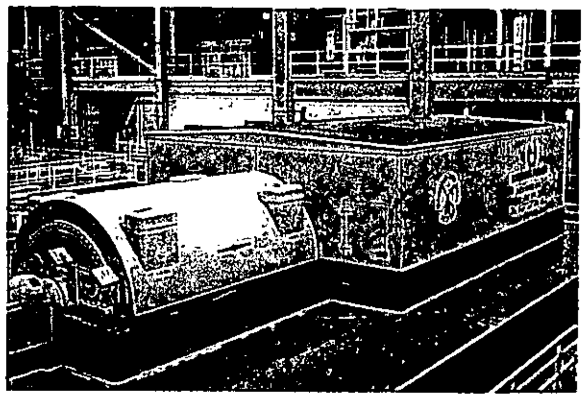
With technology that comes from a company committed to quality – a commitment that ensures GE customers receive the best value and highest level of satisfaction from their investment.

For you, GE F technology means proven superiority in efficiency, availability, maintenance and emissions control. Plus fuel flexibility that lets you adapt to changing sources and cost. In the next century, the world will demand new answers in power. GE is providing the answers today – put them to work for you now.

GE Engineered Packages: Putting Your Plants On-Line.

Engineered Packages: Putting Your Plants On-Line. *In addition to equipment, GE technology meets the needs of the industry by offering a range of system packages–with services customized to needs.*

- ***Engineered equipment package*** *– GE supplies the needed power island equipment – gas and steam turbine-generators, HRSGs, controls, transformers and switchgear. All are matched on a system-engineered basis, for a completely functional plant. And, GE guarantees output, efficiency and emissions performance. You and your plant designer retain flexibility in the specification, procurement and installation of balance-of-plant equipment. This GE package also includes technical advisors, resident engineers, plant start-up and testing, performance testing, customer training and site coordination.*
- ***Engineered package with plant design*** *– this includes plant design as an add-on to the basic engineered equipment package. GE can provide some or all outside vendor equipment and completely integrate it with the basic package.*
- ***Engineered package with plant design, construction and civil works (turnkey)*** *– with this package, GE takes on lead responsibility for the project from inception to commercial operation.*



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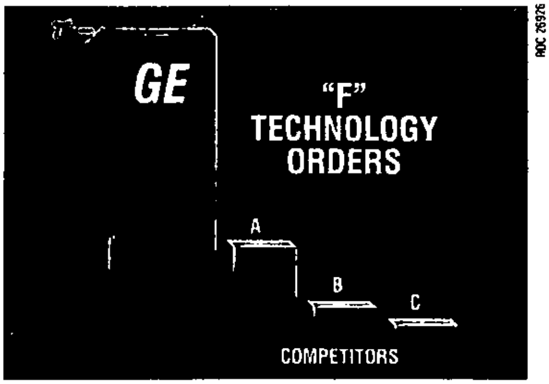
RDC 26061-3-15

GT 17338

GE Power Systems

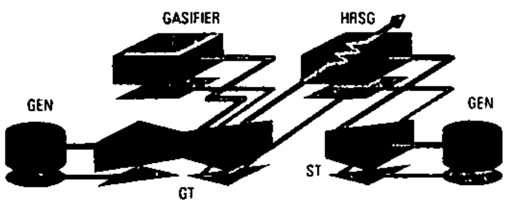
General Electric Company
Bldg. 2-103, One River Road
Schenectady, NY 12345

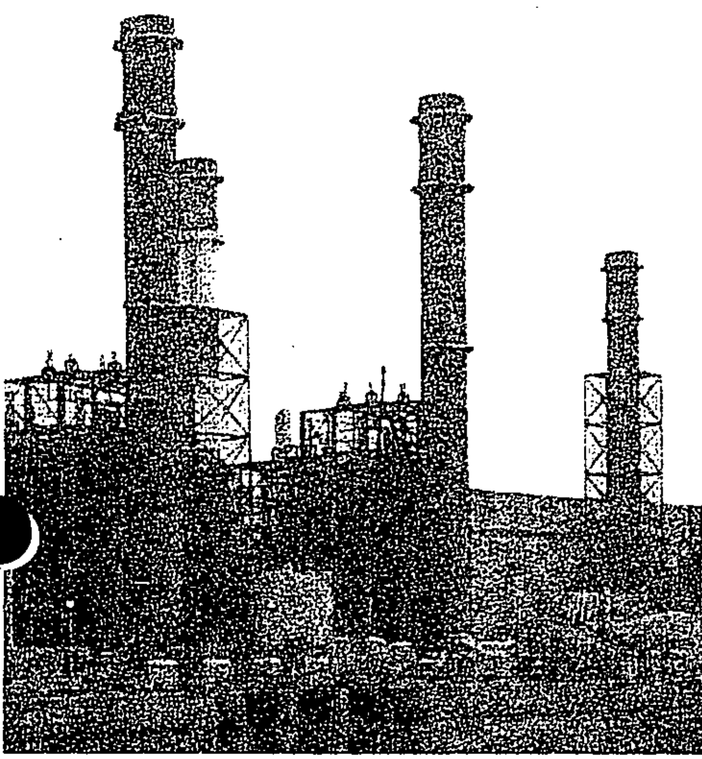


77% of Total World Commitments Go To GE Technology. *Recognizing the optimal suitability of F technology to simple cycle, combined cycle and IGCC applications, customers have made commitments for more than 75 F technology units for plants located throughout the world.**

**As of October, 1992*

IGCC.
The flexible 7FA can be readily converted to burn low heating value gas derived from coal. In IGCC applications, the 7FA can produce up to 265 MW. Because of their high firing temperature, GE F technology gas turbines are ideal for use in IGCC plants – providing plant efficiencies of up to 46%, as dictated by fuel supply and economics.





GE F technology gas turbines offer unique advantages:

High Specific Power
The power produced by the gas turbine per unit of air flow – this is the key characteristic of the gas turbine that influences performance. Thermal efficiency increases as gas turbine specific power increases. Gas turbine firing temperature is the primary determinant of specific power. GE F units lead the industry with more 2300°F (1260°C) class units in daily commercial operation than any other manufacturer.

Combined Cycle Utility
The high exhaust temperature, 1000°–1100°F (538–593°C), of GE F technology gas turbines is ideally suited to efficient combined cycles because it enables optimum combined cycle designs which utilize reheat steam turbine technology. High temperature and high pressure steam cycles are possible that simultaneously capture the maximum available gas turbine exhaust energy while delivering the highest level of efficiency. GE leads the industry with guaranteed combined cycle efficiencies reaching 55%.

Advanced Combustion
Can-annular combustors with film and impingement cooling meet the environmental requirements for applications throughout the world and provide reliable operation at high firing temperatures. Single digit (ppm) dry low NO_x is in development for all of GE's heavy-duty turbines. GE is also the most experienced supplier at meeting site requirements with wet systems or SCR (selective catalytic reduction).

Fuel Flexibility
GE gas turbines operate on liquid and gaseous fuels with a broad range of calorific value and can switch fuels without shutting down. This flexibility helps maintain high availability and makes gasified coal an especially attractive option in combined cycle configurations – with natural gas or LNG fuel as back-up for the coal gas.

Low Installed Cost
Factory packaging and containerized shipment of parts help achieve low installed cost. GE's packaging concept featuring consolidated components, controls and accessories ensures short installation time.

Reliable Operation
GE's F technology is the result of an evolutionary design development that uses extensive field service to constantly evaluate and improve parts and components. GE's high-quality manufacturing program includes operational factory testing of the gas turbine and accessory systems. Field service by experienced installation and service personnel and effective spare parts support is unmatched in the industry – ensuring the value of your investment in GE equipment throughout its service life.

Low Maintenance Cost
Continuous improvement in gas turbine equipment is made through adherence to key design parameters affecting maintenance. Analysis of feedback from the entire GE gas turbine fleet – nearly 5,000 units – makes the development of significant design improvements possible.

Application Expertise
The fuels, cycle selection and type of generation equipment you select depend on an evaluation of owning and operating costs. Experienced GE engineers will help you evaluate these, and other factors too. With the skills gained from hundreds of power plant projects, GE thermal designers are particularly qualified to provide the most efficient cycle for your application.

7FA Performance. Setting New Standards.

The MS7001FA gas turbine has become the 60 Hz gas turbine of choice for power generation because of its superior performance, reliability, availability and maintainability.

To achieve the high performance standards of the 7FA gas turbine, proven, leading-edge technologies developed with critical inputs from GE Aircraft Engines and the GE Research and Development Center have been incorporated into this advanced machine. These critical technologies include:

- advanced cooling techniques
- special high-strength, high temperature alloys
- improved high-temperature, corrosion resistant Vacuum Plasma Spray coatings

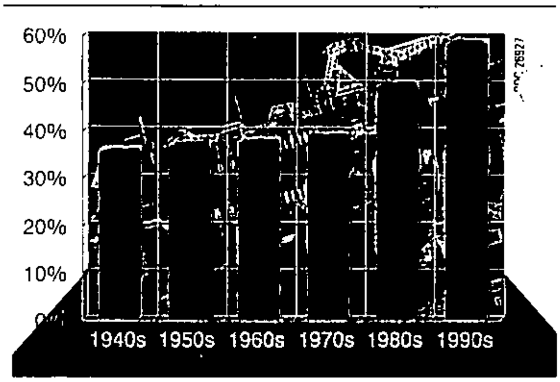
State-of-the-art design advancements have been effectively utilized in the 18-stage axial flow compressor, the multi-fuel nozzle combustion system, the first stage nozzle and buckets, and the off-base accessory arrangement. The design of the entire 7FA gas turbine, including its accessories, focuses on enhanced visual inspection and ease of maintenance.

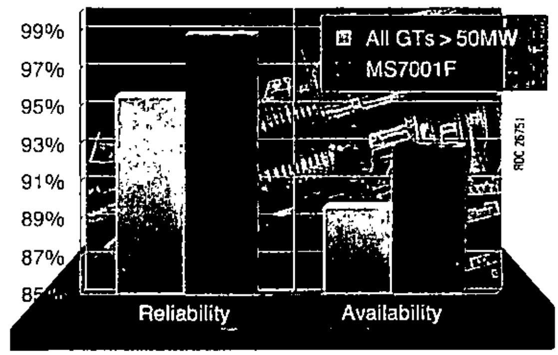
In addition to increased efficiency, the 7FA machine provides greatly improved reliability due to the design redundancy built into the accompanying SPEEDTRONIC™ Mark V control system and packaged accessory system. Significant advances in all elements of gas turbine design technologies have been made in recent years. These developments have made the improvements in performance designed into the MS7001FA possible, while maintaining the original design life standards of the now extensively experience-proven 7EA series machines.

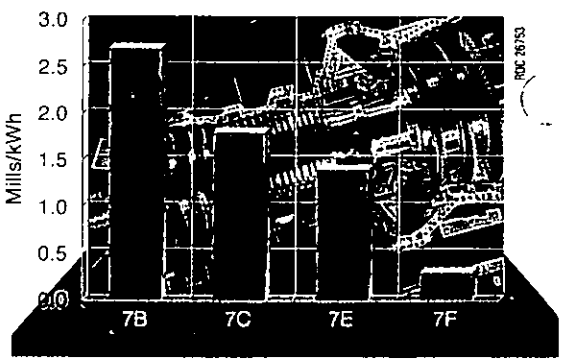
The 7FA's availability is enhanced by GE's development of materials and design of components that provide long life cycles – resulting in the industry's lowest maintenance costs. For example, inspection intervals for GE F technology units are the same as those required by earlier machines: 8,000 fired hours between combustion inspections; 24,000 hours between combustion overhauls; 48,000 hours between major maintenance.

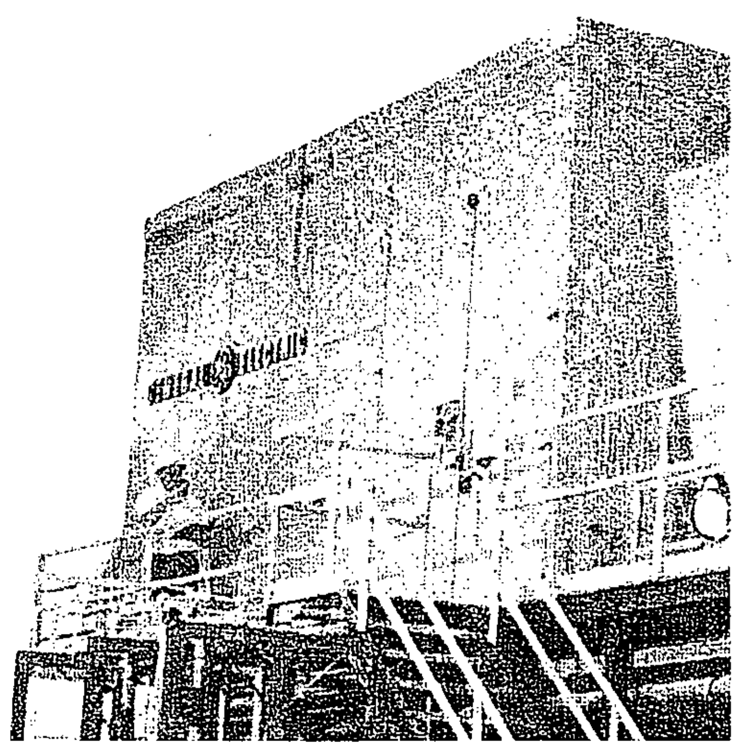
The 7FA is particularly well-adapted to large power stations. In this service, it can be used for peak shaving or integrated with waste heat recovery, where plant efficiency and longer operating hours are critical. To this end, GE design engineers have placed special emphasis on starting and operating reliability of the 7FA – as well as maintainability.

It all adds up – to value. The 7FA's high firing temperature provides immense output. Its high efficiency conserves fuel. Its operating flexibility adjusts easily to load changes. Its unmatched reliability helps keep power flowing. And its environmental compatibility strengthens your efforts to be a good neighbor. The 7FA is truly setting new standards.









HIGH EFFICIENCY

'igher firing temperature saves fuel and means .iore power. The evolution of F technology gas turbines has resulted in a step change in efficiency and output over previous frame sizes. The 7FA is expected to save 6-8% in fuel over the previous technology. Simple cycle efficiencies of F units are above 35%; combined cycle efficiencies reach 55%.*

HIGH RELIABILITY

Current operating experience demonstrates that the reliability of GE F technology machines, on a forced outage basis, is close to 99%. Both reliability – and availability – rate higher than all other gas turbines in the over 50 MW class. Such performance is the result of the continuous improvement process, inherent in GE's evolutionary design approach.

Source: North American Electric Reliability Council – Generating Availability Data System

HIGH MAINTAINABILITY

Each generation of GE gas turbines exhibits an :volutionary maintenance cost improvement over its preceding generation. At 0.3 mills/kW hour, the initial maintenance data of GE F technology operation indicates a favorable extension of this trend. GE's availability and maintenance cost advantage over competitor units of similar size and application is significant–primarily because they require inspection two to four times more often than GE units. Over 20 years, GE projects maintenance savings of as much as $2 – $5 million over competitor machines.

Source: US Federal Regulatory Commission Data for 1986 – 1989 (F data from 1990 operating experience)

F Technology Fulfilling The Promise: Virginia Power's Chesterfield #7 And #8.

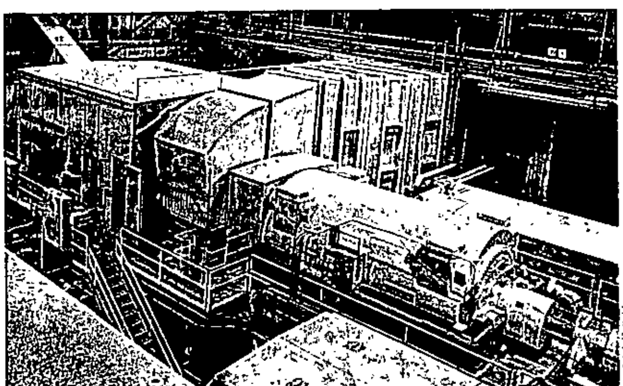
The first GE F technology gas turbine was installed at Virginia Power's Chesterfield Station Unit #7 in 1990 as part of a STAG™ (steam and gas turbine) 107F combined cycle unit. Now with thousands of hours of operating experience in combined cycle, the F generation of GE gas turbines has fulfilled an ambitious development promise – reliability levels approaching 99% and availability levels above 90%.

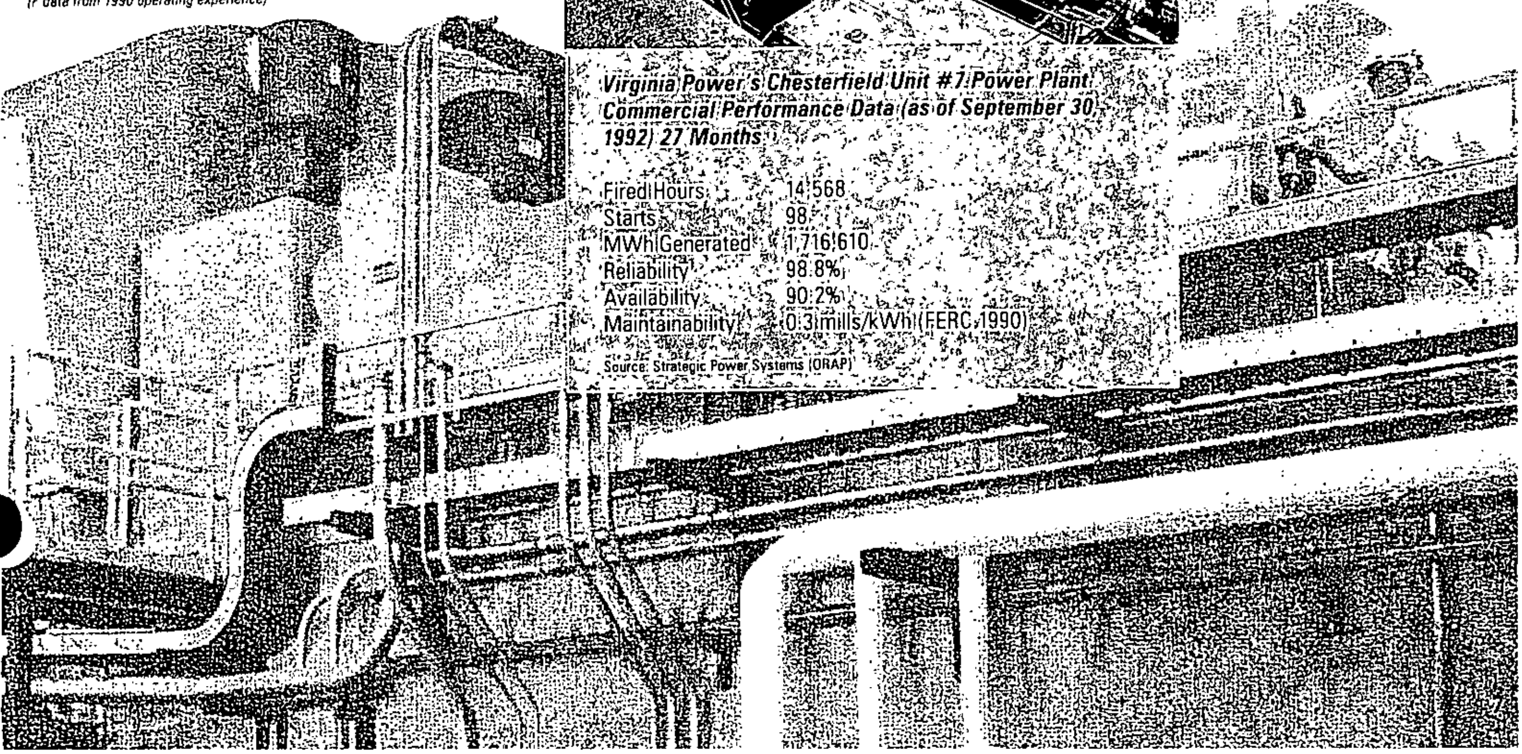
Chesterfield #7, a GE turnkey project, began commercial service in June 1990. Installed with less than three years between contract and initial output, it clearly demonstrates the viability of F technology applications for power producers facing increased demand and projected shortages of electrical power – while minimizing capital requirements.

With Chesterfield #8, on-line in 1992, the two STAG™ 107F plants deliver 432 MW of power with combined cycle thermal efficiency exceeding 50%.

Both STAG™ 107F units operate on natural gas or distillate oil fuel with the flexibility to convert to medium-Btu gas derived from coal, if that alternative becomes economically appropriate. At 2300° F (1260° C) – the industry's highest firing temperature gas turbine in daily operation – this F technology power plant delivers greater output and saves fuel in combined cycle applications.

Output, efficiency, flexibility. GE F technology was the answer for Virginia Power, and can be the answer for your power plant application.





Virginia Power's Chesterfield Unit #7 Power Plant Commercial Performance Data (as of September 30, 1992) 27 Months

Fired Hours	14,568
Starts	98
MWh Generated	1,716,610
Reliability	98.8%
Availability	90.2%
Maintainability	0.3 mills/kWh (FERC 1990)

Source: Strategic Power Systems (ORAP)

7FA Design. Evolutionary Technology.

The reliability of the MS7001FA gas turbine has been confirmed by GE's design philosophy, which centers on the principle of geometric scaling. It builds on a solid analytical foundation and years of experience in the field. The design of the MS7001FA gas turbine was derived using aerodynamic scaling from the MS7001EA machine.

Through scaling, GE increases the physical size of a gas turbine while maintaining the geometric similarity of components proven in predecessor units. Operating factors such as temperatures, pressures, blade angles and stresses are kept constant, while critical cycle parameters such as pressure ratios and efficiency are maintained. Therefore, experience gained on a parent component is directly applicable to a scaled component.

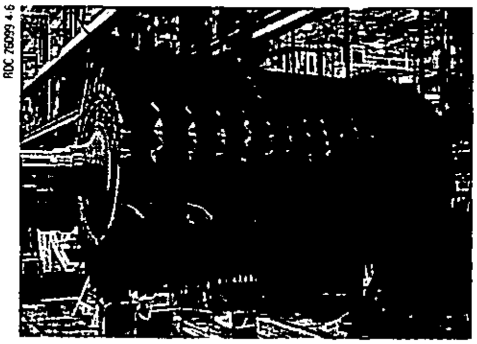
These larger designs also gain from improved components and materials, prudently applied to boost power and thermal efficiency. Finally, the new units are tested extensively in development facilities to confirm the design under actual operating conditions. In this manner, successful GE designs are carefully scaled to larger size – the evolution of the F technology units being the latest example.

Proof In Design: The Major Elements.

1. AXIAL COMPRESSOR.

The 7FA benefits from several decades of compressor design evolution that have led to ever higher air flow and efficiency. The compressor is an 18-stage axial flow design similar to the MS7001EA compressor, but with an increased annulus area and the addition of a zero stage. The 7FA is aerodynamically similar to the 7EA and most of the blading is identical except for length – higher strength alloys have been applied to the compressor blades to accommodate the increased blade stresses resulting from the increased airflow and higher pressure ratio. By starting with a reliable design and making evolutionary improvements, GE has greatly improved overall compressor performance without sacrificing reliability or mechanical integrity.

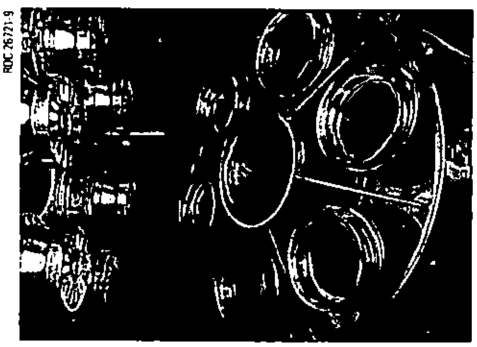
RDC 76099 4-6



2. COMBUSTOR.

The 7FA combustor has the same proven size and configuration as that of the 7EA; however, the number of combustion chambers is increased from 10 to 14. It is designed to have the lowest environmental impact while maintaining the highest reliability standards. The 7FA's combustion liner cap incorporates six fuel nozzles to reduce combustion wear and increase inspection intervals. The construction of the 7FA's combustion liner is similar to the 7EA liner but is 30% thicker and 8.4 inches (213 mm) shorter, providing effective cooling of the liner wall. A plasma-sprayed thermal coating is applied to the liner's surface to provide enhanced high-temperature strength and reduction of metal temperatures and thermal gradients. Unlike competitive units, the can-annular combustor arrangement provides the added assurance of full-scale factory and laboratory testing at rated flow, pressure and temperature.

RDC 26721-9



3. TURBINE.

The high performance gains available in the 7FA are largely due to a dramatic increase in baseload firing temperatures, climbing in two decades from 1500° F (816° C) to 2350° F (1288° C). This has been achieved by improved nozzle and bucket materials, and the air cooling of this hardware. The turbine section consists of three stages with air cooling provided to all three nozzle stages and to the first two bucket stages. The turbine rotor is constructed of three wheels separated by spacers, with an aft bearing shaft. Both the compressor and turbine rotors are bolted together – this construction ensures a rugged, rigid structure with flexing critical speeds well above operating speed.

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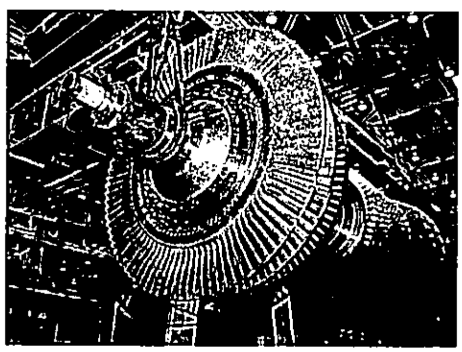
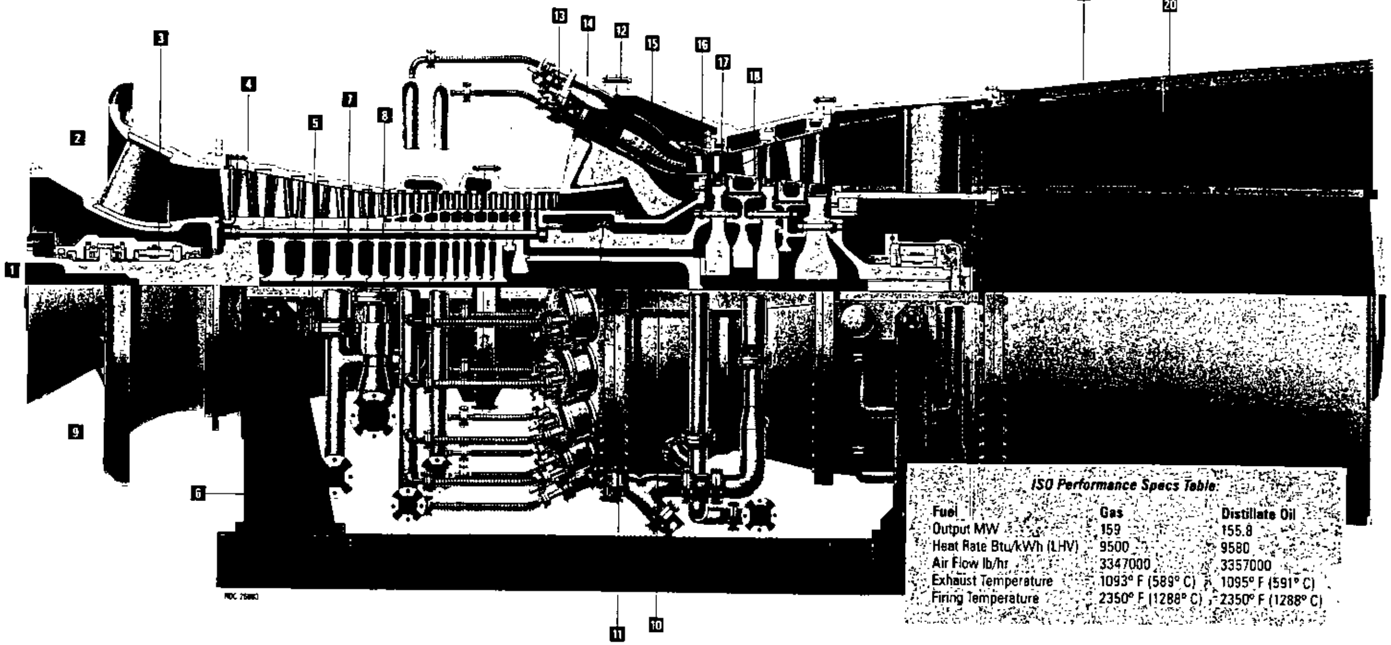


7FA Design. Revolutionary Results.



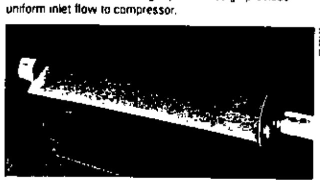
ISO Performance Specs Table:

Fuel	Gas	Distillate Oil
Output MW	159	155.8
Heat Rate Btu/kWh (LHV)	9500	9580
Air Flow lb/hr	3347000	3357000
Exhaust Temperature	1093° F (589° C)	1095° F (591° C)
Firing Temperature	2350° F (1288° C)	2350° F (1288° C)

COMPRESSOR

1. Load Coupling – short rigid coupling can be directly connected to generator flange

2 Axial/Radial Inlet Casing – proven design provides uniform inlet flow to compressor.



3. Journal Bearings – bearings are tilting-pad type for improved rotor stability and are also pressure-lift for reduced break-away torque.

4. Compressor Blading – an evolution from the 7EA compressor with a zero stage added Blade length increased for added flow. Blade material upgraded for more demanding requirements Shrouded stator 17 and exit guide vanes are utilized for improved cyclical life

5. Compressor Design – based on proven axial-flow design One piece casing allows easier start-up Casing material upgraded to accommodate higher temperature and pressure

6. Rigid Forward Support – in combination with forward thrust bearing, limits thermal expansion of gas turbine into generator

7. Wheel Construction – machined to nearly constant stress cross-section with contact faces at maximum diameter for high rotor stiffness

8. Through-Bolt Construction – large bolts at maximum bolt circle provide rigid rotor with required torque capability for front-end drive

9. Inlet Orientation – available in up, down or side arrangement

STATOR CASINGS

10. Horizontally Split – all casings split on horizontal centerline with through-bolting to facilitate maintenance.

COMBUSTION

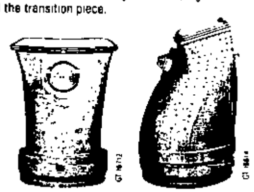
11. Combustor Bulkhead – combustor outer cans attached over elongated holes in combustor bulkhead to permit removal of transition piece without lifting turbine shell

12. Top and Bottom Manway Access – permits an alternative method for removing combustor transition piece and stage 1 nozzle without lifting turbine shell

13. Fuel Distribution – single fuel line connection for each combustor with manifolding to six fuel nozzles built into combustor end cover

14. Reverse Flow Combustor Chambers – supplement the impingement and film cooling of the liners, prolonging parts life

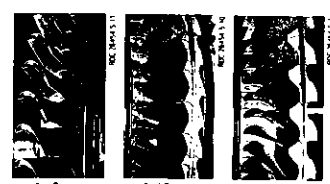
15 Impingement Cooled Combustor Transition Piece – separate perforated sleeve around transition piece causes compressor discharge air to impinge on and effectively cool the transition piece.



TURBINE

16. Nozzle Design – sidewalls and internal surfaces of vanes impingement cooled with spent air used for extensive film cooling

17. Stage 1 Stationary Shroud Design – gas path insert of high temperature alloy, extensively convection impingement and film cooled and coated for maintaining tight clearances with the stage 1 bucket tip



1st Stage *2nd Stage* *3rd Stage*

18 Bucket Design – stage 1 bucket is directionally solidified and uses a turbulated serpentine cooled design with trailing edge bleed cooling, based on GE Aircraft Engine technology Stage 2 uses turbulated radial cooling holes Stage 3 is uncooled Stages 2 and 3 have integral z-lock shrouds for vibration control, and all three stages have long shanks for vibration control and isolation of gas path temperatures from the turbine wheels

EXHAUST

19. Exhaust Diffuser – axial design (permitted by front end drive) is blanket insulated for thermal stability, safety and reduced heat loss from exhaust before entering heat recovery system

20 Exhaust Thermocouples – sets of thermocouples supply signals to each of the three SPEEDTRONIC™ Mark V computers The thermocouples are used for control and also for monitoring the combustion system

The MS7001FA gas turbine is available as a single-shaft machine driving a generator attached to the compressor end by a rigid coupling. Running speed is 3600 rpm (60 Hz direct drive). The compressor is a high-efficiency 18-stage device with extraction provisions at stages 9 and 13. There are 14 combustors in a can-annular arrangement. The turbine has three stages, similar in design to those of its predecessors

The rotor is bolted disc-and-shaft construction consisting of a compressor group and a turbine group. The compressor rotor consists of 18 bladed discs, the first and last of which incorporate stub shafts These discs are of extremely stiff design, and the first bending critical harmonic occurs well beyond full rated speed

The stator is a multiple casing structure of fabricated and cast elements. The turbine shell and exhaust frame are steel fabrications. The combustion wrapper is incorporated into the turbine shell.

Compressor flow was increased from 643 6 lb/sec (291 9 kg/sec) for the 7EA to 921.4 lb/sec (418.0 kg/sec) for the 7FA by adding a "zero stage" to the inlet end and by increasing annular area and opening inlet guide vanes. The resulting transonic stage was designed with airfoil design tools perfected by GE Aircraft Engines. Compressor blade material is C-450 for stages 0-8, and is 403Cb alloy for stages 9-17 and exit guide vanes 1 and 2. These alloys are well suited for application in chemically aggressive environments without a coating system.

The 7FA is designed to operate on low-energy-content fuels, like those supplied by coal gasifiers, allowing increased output, efficiency and maintenance.

TURBINE BUCKETS

Higher firing temperatures require first stage buckets with a cooling arrangement derived from GE's CF-6 aircraft engine. Second stage buckets are in the same temperature environment as the first stage buckets of previous Frame 7 design and are cooled by similar radial cooling passages. Second and third stage buckets are of the long shank, shrouded design, proven in thousands of machines.

ALLOYS

The patented GTD-111 high nickel alloy used in the 7FA buckets is derived from current aircraft bucket alloys, with modifications to enhance long-term corrosion and oxidation properties. The first stage buckets are directionally solidified – the bucket grain structure is oriented along its long axis to provide greater strength. Coatings are chosen in relation to the temperature environment of the bucket. First and second stages are coated with GE's proprietary Vacuum Plasma Spray, which doubles corrosion life compared to earlier coating processes. First and second stages have aluminide diffusion coating utilizing a pack process as an internal coating and external overcoat. The bucket interior cooling passages are also coated. The third stage is coated by a pack process with a system that addresses low-temperature hot corrosion.

GE has also developed a nickel-base alloy that can be applied to the nozzle structures of the 7FA. This patented alloy – GTD-222 – is used on second and third stage nozzles, reducing cooling flow required by the nozzles and significantly extending their creep life. Stage 1 nozzles are FSX-414 alloy.

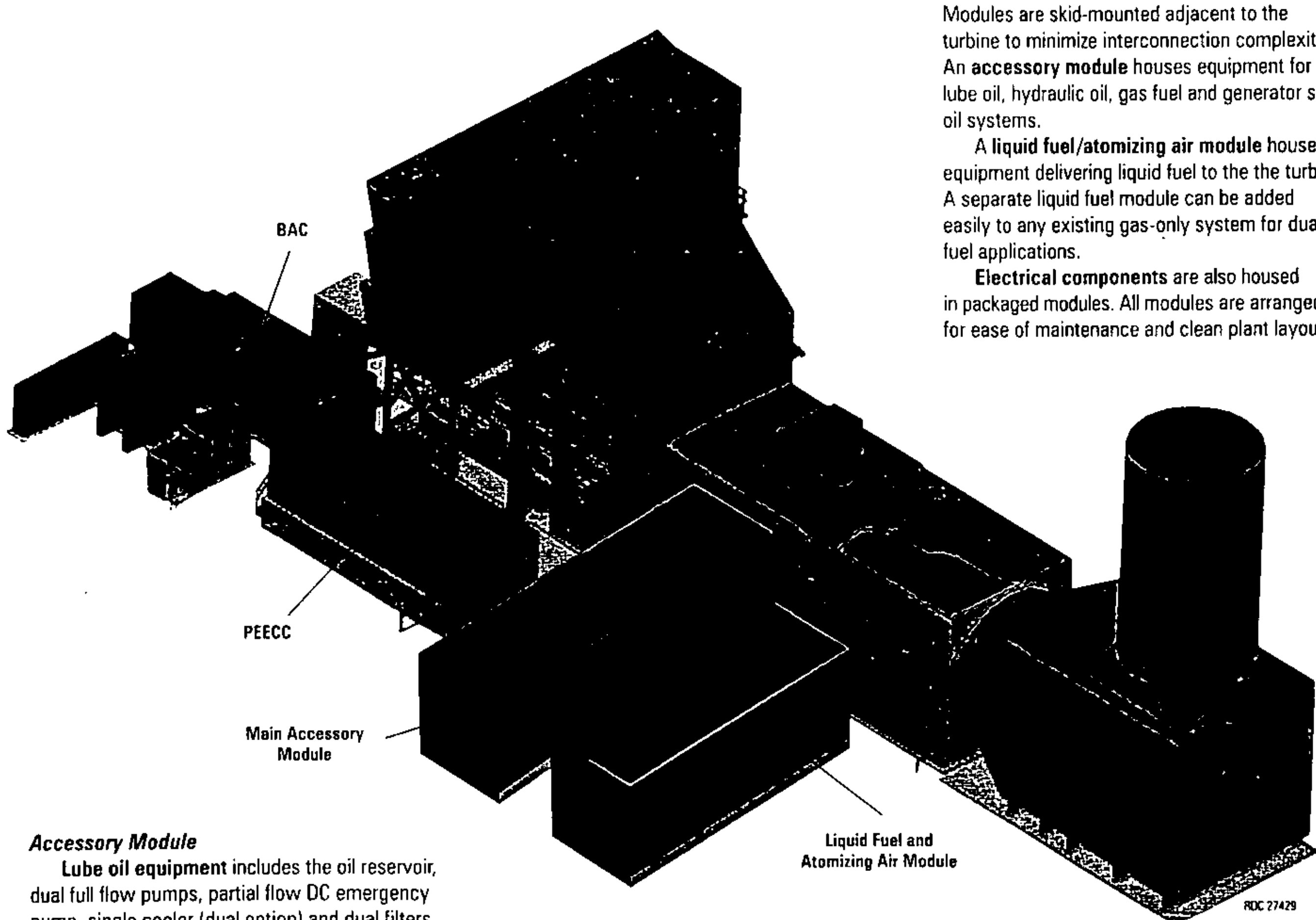
Turbine wheels are forged of a nickel alloy which provides the benefits of lower cooling requirements and tighter tip clearances.

7FA. Prepackaged For Rapid Installation And Fuel Flexibility.

The modularized 7FA package assures fast installation with minimum installation cost. Modules are skid-mounted adjacent to the turbine to minimize interconnection complexities. An **accessory module** houses equipment for lube oil, hydraulic oil, gas fuel and generator seal oil systems.

A **liquid fuel/atomizing air module** houses equipment delivering liquid fuel to the the turbine. A separate liquid fuel module can be added easily to any existing gas-only system for dual fuel applications.

Electrical components are also housed in packaged modules. All modules are arranged for ease of maintenance and clean plant layout.

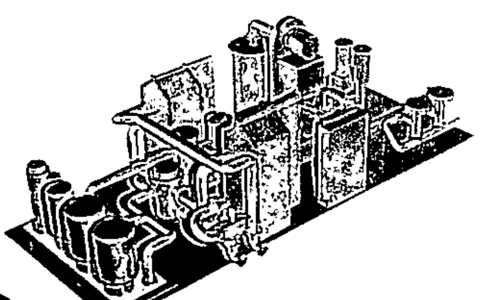


Accessory Module

Lube oil equipment includes the oil reservoir, dual full flow pumps, partial flow DC emergency pump, single cooler (dual option) and dual filters.

High pressure hydraulic equipment includes dual pumps and filters for control devices, plus a single pump-and-filter for pressure lift bearings and generator seal oil equipment.

Gas fuel equipment includes stop, control, purge and vent valves together with connecting piping in a prepackaged arrangement. The gas supply connection and interconnecting piping to the turbine's gas fuel nozzles are also included.

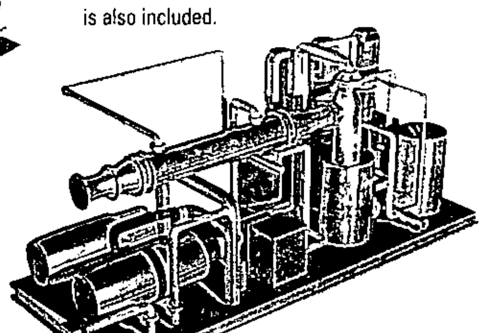


RDC 27422-1

Liquid Fuel/Atomizing Air Module

Liquid fuel equipment includes a main filter, stop valve, single full-size fuel pump, bypass valve and flow divider. (Redundant pumps and filters are also available.) Liquid fuel is obtained from an off-base fuel forwarding skid.

Atomizing air equipment includes a single full size main compressor (dual option), partial size purge compressor, cooler, filter and control valves. Air is supplied from the gas turbine compressor. Interconnecting liquid fuel and atomizing air piping from the module to the turbine is also included.



RDC 27422-2

Electrical Systems

Pre-wired packaging reduces on-site conduit, cable and wiring requirements. Electrical protection and controls are housed in the **packaged electrical and electronic control center** (PEECC) consisting of low voltage motor control centers, MARK V combustion turbine and generator control panels, and the emergency DC battery system. The microprocessor-based excitation system's excitation transformer (PPT), PT's and breakers are all pre-wired and housed in a **bus accessory compartment** (BAC).

A **static start system** is used for F-technology combustion turbines to provide dependable, rapid full-load starts.

7FA Accessories: Proven Components, Integrated for Highest System Efficiency

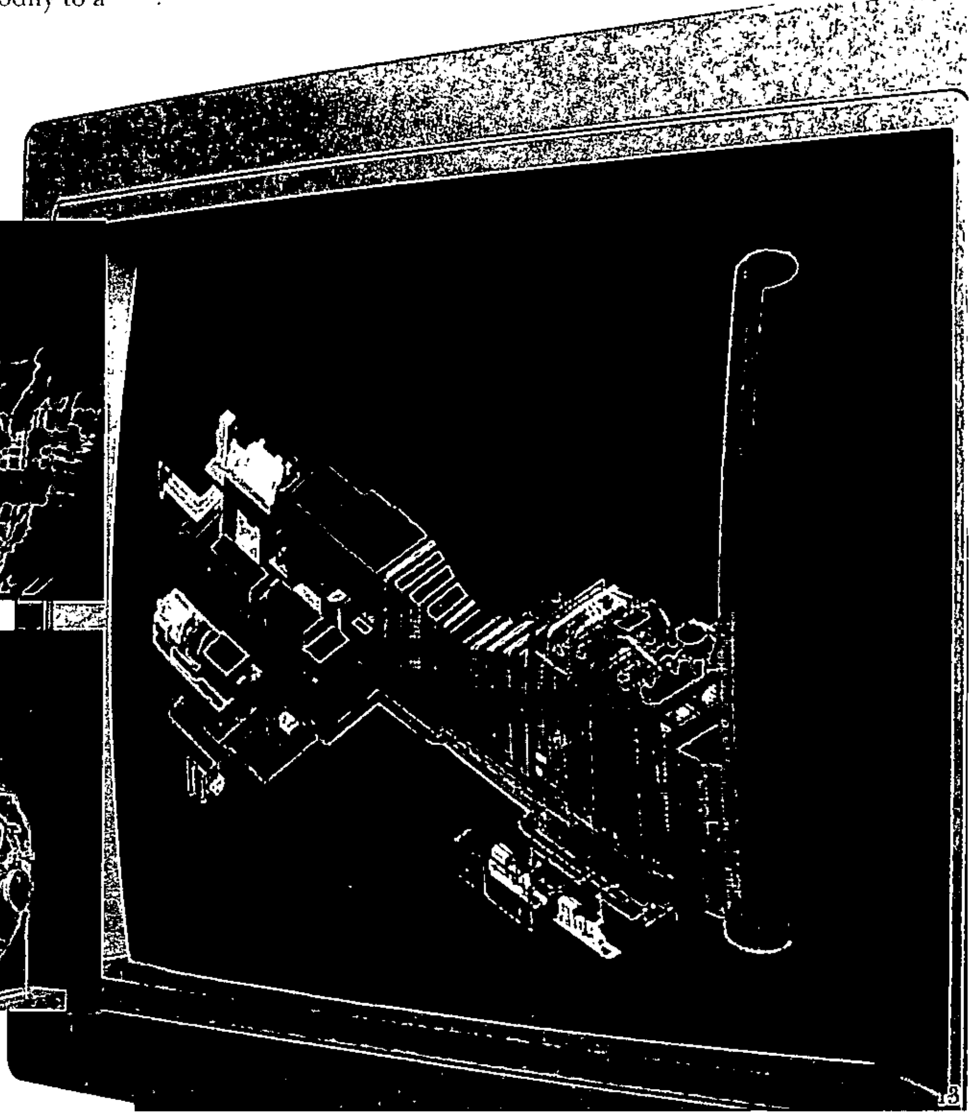
GE equipment provides you with two significant advantages. First, you can choose from the broadest line of power plant products of any manufacturer in the world – to fit site and duty requirements. Second, all GE systems are designed for optimal integration, producing the highest levels of reliability and efficiency – backed by GE guarantees.

Controls

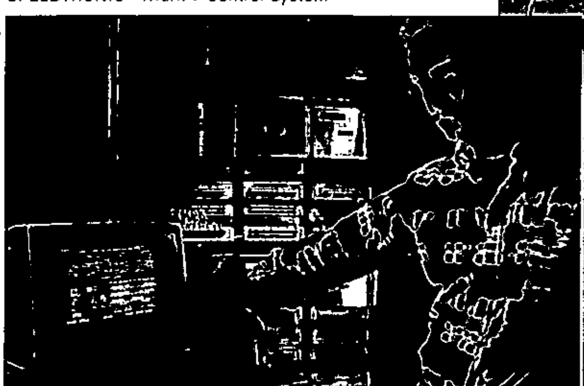
In addition to increased efficiency, the 7FA machine provides unmatched reliability due to the redundancy built into GE's state-of-the-art SPEEDTRONIC™ Mark V Control System. Because this microprocessor-based turbine control employs a distributed processor design and a redundant architecture, its overall performance is unmatched in the industry. The Mark V uses independent digital controllers to achieve the reliability of triple redundancy for turbine control and protective functions. A PC-based color graphic operator interface displays control and monitoring status and executes operator commands from logical, uncluttered screens that the user can modify to a particular need. GE integrates the Mark V with the plant controls in STAG™ combined cycle, providing the industry's optimum control solution.

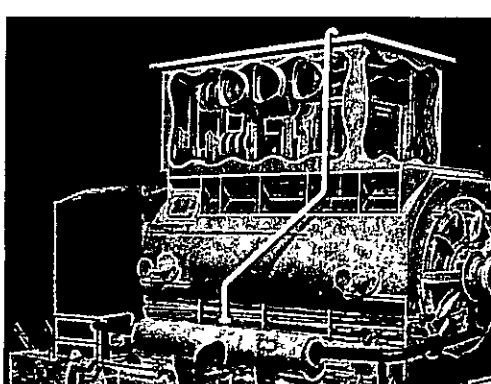
Generators

GE offers a full line of factory assembled air-cooled and hydrogen-cooled generators to complement its gas turbine product line. The advanced, packaged design GE 7FH2 hydrogen-cooled generator is used with the 7FA gas turbine. The 7FH2 is designed for compactness and ease of service and maintenance. Factory assembly allows delivery of the generator with the rotor already installed, along with lube oil piping and wiring routed in conduit. This packaged turbine-generator set can reduce installation time and cost by up to 40%. Static start eliminates the need for a starting motor and torque converter. Its fast-acting, static excitation system provides the highest initial response needed under fault conditions. The 7FH2's Class F insulation on both rotor and stator provides dielectric and mechanical strength to ensure long life. Designed for high reliability, maximum safety and efficiency, the 7FH2 is the latest example of GE's advanced design capability.



SPEEDTRONIC™ Mark V Control System





7FH2 Generator