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PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION FOR BRANDY BRANCH FACILITY

SUBMITTED BY
Jacksonville Electric Authority

Rec'd May 19, 1999

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PSD-FL-267

PREPARED BY
Black & Veatch

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1.0 Introduction

Jacksonville Electric Authority (JEA) propose to develop a new electrical power generating station at their Brandy Branch Facility (herein after referred to as the Project) near Baldwin City, Florida. The proposed Project will be comprised of three simple cycle combustion turbines (SCCT) rated at a nominal 170 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a back-up fuel. New major support facilities for the Project will include water and wastewater treatment facilities, water storage tanks, storm water detention pond, transmission line, and fuel oil storage tanks.

This report is technical support document for the Prevention of Significant Deterioration Air Permit Application. The following sections contain a project characterization, Best Available Control Technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project including a general description of the location, facility, and emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

The Project is located in the western, rural part of Duval County, Florida. Figure 2-1 shows the general location of the Project which is approximately 1 mile northeast of Baldwin City, 4 miles north-northwest of US Naval Air Station Cecil Field, and 4 miles southwest of US Naval Air Station Whitehouse Field. The nearest Federal PSD Class I Areas are the Okefenokee Wilderness Area and the Wolf Island Wilderness Area located approximately 34 km northwest and 127 km northeast of the Project, respectively.

The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

The Project will be composed of three SCCTs. Each SCCT is a General Electric 170 MW simple cycle combustion turbine (Model PG7241FA) firing natural gas as the primary fuel, with distillate fuel as back-up. The energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as they expand through the turbine sections of the SCCTs. The rotating mechanical energy will be converted into electrical energy via a shaft on the SCCTs connected to an electrical generator. The remaining combustion gases will be exhausted to the atmosphere through an exhaust stack.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- Three SCCTs firing natural gas as the primary fuel, with distillate fuel as back-up.
- Three No. 2 distillate fuel oil storage tanks approximately 1,000,000 gallons each.
- A diesel fired emergency fire water pump.

Figure 2-1
(Site Location)

2.3.1 SCCT Emissions

Performance data for the SCCTs, based on vendor data from GE at design loads of 50, 75, and 100 percent, natural gas and distillate fuel firing, and ambient air temperatures of 20°F, 59°F, and 95°F are provided in Attachment 1.

Ambient temperature data were selected based on meteorological data from Jacksonville, Florida. An ambient temperature of 20°F represents the winter seasonal site temperature and corresponds to maximum heat input and power generation. An ambient temperature of 59°F represents the average annual site temperature which is representative of the average heat input rate. An ambient temperature of 95°F represents the summer seasonal site temperature and corresponds to the lowest heat input rate for the combustion.

The maximum pound per hour emission rates considering all ambient temperatures and partial load operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

2.3.2 No. 2 Distillate Fuel Oil Storage Tank

The three fuel oil storage tanks are estimated to have a capacity of 1,000,000 gallons each. Emissions of VOCs from the fuel oil storage tank were estimated using the EPA's TANKS (Ver. 3.1) program. Results of the TANKS emission modeling are included in Attachment 2. The VOC emissions from the fuel oil storage tanks are approximately 0.83 tpy and are included in the total Project's PTE calculations.

2.4 Maximum Project Potential to Emit

The potential to emit was estimated from the maximum hourly emission rate for each pollutant at an ambient temperature of 59°F (average annual) considering 50 to 100 percent load simple cycle operation, and 800 hours of distillate fuel oil firing (0.05 % sulfur) with 4,000 hour a year of natural gas firing. The Project's potential to emit for each pollutant is summarized in Table 2-2. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included in Attachment 3.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs; the PSD program outlined in 40 CFR 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment area with respect to all pollutants. As such, the PSD

Table 2-1 Project Maximum Emission Rates (lb/h)*		
Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NOx	84.8	338.0
SO2	1.1	104.3
CO	52.0	74.0
PM/PM10	9.0	17.0
VOC	3.0	3.0

*Maximum pound per hour emission rates for the SCCTs considering average ambient temperature and partial load operation for natural gas and distillate fuel oil firing.

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NOx	857.7[a]	40	yes
SO_2	124.3[a,b]	40	yes
CO	366.2[a]	100	yes
PM/PM_{10}	74.5[a,c]	25/15	yes
VOC	21.3[a,f]	40	no
Sulfuric Acid Mist	15.2[a,d]	7	yes
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Vinyl Chloride	negl.	1	no
Total Fluorides	negl.	3	no
Mercury	0.0007[e]	0.1	no
Beryllium	0.0002[e]	0.0004	no
Lead	0.042[e]	0.6	no

[a]Based on maximum lb/h emission rate at 59°F conditions for all loads and operating scenarios; assuming 4,000 and 800 hours per year of natural gas and distillate fuel oil firing, respectively.

[b]Based on 0.05% sulfur distillate fuel oil, 0.2 gr/100 scf sulfur natural gas, and assuming 100 percent conversion to SO_2.

[c]Assumes front half PM/PM_{10} emissions.

[d]Conservatively assuming a 10 percent conversion of SO2 to SO3, and a molecular ratio of 1.22 from SO3 to H2SO4.

[e]Based on AP-42 emission factors, a maximum heat input of 1,934.7 MBtu/h and distillate fuel oil firing for 800 hours per year.

[f]VOC PTE is based on potential emissions from the Project's combustion sources and emissions from the fuel oil storage tanks.

Note: PTE calculations are provided in a spreadsheet included in Attachment 3.

program will apply to the Project, as administered by the state of Florida under 62-212.400, F.A.C., Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.

2.5.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the ambient air quality standards (AAQS) while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The Brandy Branch Facility is not one of the 28 major source categories but does has a PTE greater than 250 tpy for at least one regulated pollutant. Additionally, the estimated emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (SAM) resulting from the proposed Project, exceed the PSD significant emissions levels of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, CO, and PM/ PM_{10}, and SAM are subject to PSD review as a new major source. The PSD review includes a BACT analysis, air quality impact analysis (AQIA), and an assessment of the total project's impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis.

3.0 Best Available Control Technology

A best available control technology (BACT) analysis for Brandy Branch has been included as Attachment 4.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those pollutants, which will have a PTE greater than the PSD significant emission rate (i.e., NO_x, SO_2, CO, and PM/PM_{10}). (SAM emissions are discussed in the BACT, Section 3.0, but were not assessed in the application). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of JEA in a memorandum from Black & Veatch dated November 20, 1998 (Attachment 5).

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 98356) air dispersion model was used to predict maximum ground level concentrations associated with the Project emissions. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to access pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with EPA guidance.

4.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

4.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing each SCCT unit's proposed operating load range (i.e., 50, 75, and 100 percent loads) with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from vendor performance data to produce the worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping".

The worst-case representative stack parameters and emission rates for each load, fuel type, and ambient temperature considered in the analysis are presented in Table 4-1. A spreadsheet used in determining the load based representative emissions and stack parameters from the vendor performance data is included in Attachment 3.

4.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the proposed Project's location, it was concluded that over 50 percent of the area surrounding the Project is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

4.2.3 GEP Stack Height Determination

The Project's proposed buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. EPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document was followed in this evaluation. Structure dimensions and relative locations were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for each SCCT is 32.8 m (107.6 ft).

4.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

Table 4-1
Representative (*Enveloped*) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis

Operating Scenario/Fuel	ISCST3 Source ID[a]	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO_x	SO_2	CO	PM/PM_{10}[d]
SCCT Natural Gas	SNG1	100	27.43	5.49	45.04	855.93	13.36	0.14	6.55	1.13
	SNG7	75	27.43	5.49	37.85	873.15	10.58	0.12	5.17	1.13
	SNG5	50	27.43	5.49	32.42	899.82	8.32	0.09	4.28	1.13
SCCT Distillate Fuel Oil	SFO1	100	27.43	5.49	46.27	848.71	42.59	13.14	8.69	2.14
	SFO7	75	27.43	5.49	38.54	912.59	34.14	10.64	6.43	2.14
	SFO5	50	27.43	5.49	33.06	922.04	26.33	8.30	9.32	2.14
SCCT Annualized[b]	A1T	100	27.43	5.49	47.78	875.37	6.70	1.19	N/A	0.57
	A7T	75	27.43	5.49	39.54	888.15	5.36	0.97	N/A	0.57
	A5T	50	27.43	5.49	33.69	913.15	4.25	0.76	N/A	0.57
Diesel Fire Pump[d]	SFP	N/A	7.32	0.15	60.02	615.93	N/A	0.004	0.002	0.004
	AFP	N/A	7.32	0.15	60.02	615.93	0.009	0.0006	N/A	0.0006

[a]S or A refer to short-term or annualized emission rate; NG or FO refer to natural gas or distillate fuel oil fired; 1,7,or 5 refer to 100, 75, or 50 percent load; and T refers to total emission sources.

[b]Annualized emission rate based on 4,000 hours of natural gas firing and 800 hours of distillate fuel oil firing.

[c]Assumes front half PM/PM_{10} Emissions.

[d]Assumes the diesel fire pump operates 52 hours per year for testing purposes.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the proposed Project was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 2 km, 250 m spacing from 2 to 5 km, 500 m spacing from 5 to 7 km, and then 1,000 m spacing from 7 to 10 km. Receptor spacing of 50 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures. The flat terrain option was used for all receptor points.

4.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1984-1988) of surface and upper air meteorological data from Jacksonville, Florida and Waycross, Georgia, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

4.3 Model Results

As presented in Section 2.0, the Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, CO, and PM/PM_{10}. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, SO_2, CO, and PM/PM_{10} for each applicable averaging period.

Tables 4-2 through 4-9 present the results for the 5 year refined modeling period (1984-1988) for each pollutant and applicable averaging period. The underlined concentrations in each table represent the maximum modeled predicted impacts in each case.

Figure 4-1
(Receptor Location Plot)

Table 4-2
ISCST3 Model Predicted Maximum Annual Concentrations of NO_x

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
A1T	Annual	100	1984	0.54	408,892.0	3,354,573.5
A7T		75		0.54	408,892.0	3,354,573.5
A5T		50		0.54	408,892.0	3,354,573.5
A1T		100	1985	0.57	408,892.0	3,354,573.5
A7T		75		0.57	408,892.0	3,354,573.5
A5T		50		0.57	408,892.0	3,354,573.5
A1T		100	1986	0.58	408,892.0	3,354,573.5
A7T		75		0.58	408,892.0	3,354,573.5
A5T		50		0.58	408,892.0	3,354,573.5
A1T		100	1987	0.51	408,892.0	3,354,573.5
A7T		75		0.51	408,892.0	3,354,573.5
A5T		50		0.51	408,892.0	3,354,573.5
A1T		100	1988	0.52	408,892.0	3,354,573.5
A7T		75		0.52	408,892.0	3,354,573.5
A5T		50		0.52	408,892.0	3,354,573.5

Table 4-3
ISCST3 Model Predicted Maximum Annual Concentrations of SO_2

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
A1T	Annual	100	1984	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1985	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1986	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1987	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1988	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5

Table 4-4
ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	3-Hour	100	1984	13.36	408,892.0	3,354,573.5
SNG7		75		13.36	408,892.0	3,354,573.5
SNG5		50		13.36	408,892.0	3,354,573.5
SNG1		100	1985	12.32	408,892.0	3,354,573.5
SNG7		75		12.32	408,892.0	3,354,573.5
SNG5		50		12.32	408,892.0	3,354,573.5
SNG1		100	1986	14.88	408,892.0	3,354,573.5
SNG7		75		14.88	408,892.0	3,354,573.5
SNG5		50		14.88	408,892.0	3,354,573.5
SNG1		100	1987	11.45	408,892.0	3,354,573.5
SNG7		75		11.45	408,892.0	3,354,573.5
SNG5		50		11.45	408,892.0	3,354,573.5
SNG1		100	1988	9.26	408,892.0	3,354,573.5
SNG7		75		9.26	408,892.0	3,354,573.5
SNG5		50		9.26	408,892.0	3,354,573.5
SFO1	3-Hour	100	1984	13.36	408,892.0	3,354,573.5
SFO7		75		13.36	408,892.0	3,354,573.5
SFO5		50		13.36	408,892.0	3,354,573.5
SFO1		100	1985	12.32	408,892.0	3,354,573.5
SFO7		75		12.32	408,892.0	3,354,573.5
SFO5		50		12.32	408,892.0	3,354,573.5
SFO1		100	1986	14.88	408,892.0	3,354,573.5
SFO7		75		14.88	408,892.0	3,354,573.5
SFO5		50		14.88	408,892.0	3,354,573.5
SFO1		100	1987	11.45	408,892.0	3,354,573.5
SFO7		75		11.45	408,892.0	3,354,573.5
SFO5		50		11.45	408,892.0	3,354,573.5
SFO1		100	1988	9.26	408,892.0	3,354,573.5
SFO7		75		9.26	408,892.0	3,354,573.5
SFO5		50		9.26	408,892.0	3,354,573.5

Table 4-5
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO_2

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	24-Hour	100	1984	3.35	408,941.9	3,354,579.0
SNG7		75		3.35	408,941.9	3,354,579.0
SNG5		50		3.35	408,941.9	3,354,579.0
SNG1		100	1985	4.22	408,892.0	3,354,573.5
SNG7		75		4.22	408,892.0	3,354,573.5
SNG5		50		4.22	408,892.0	3,354,573.5
SNG1		100	1986	3.55	408,892.0	3,354,573.5
SNG7		75		3.55	408,892.0	3,354,573.5
SNG5		50		3.55	408,892.0	3,354,573.5
SNG1		100	1987	3.57	408,892.0	3,354,573.5
SNG7		75		3.57	408,892.0	3,354,573.5
SNG5		50		3.57	408,892.0	3,354,573.5
SNG1		100	1988	2.20	408,892.0	3,354,573.5
SNG7		75		2.20	408,892.0	3,354,573.5
SNG5		50		2.20	408,892.0	3,354,573.5
SFO1	24-Hour	100	1984	3.36	408,941.9	3,354,579.0
SFO7		75		3.36	408,941.9	3,354,579.0
SFO5		50		3.35	408,941.9	3,354,579.0
SFO1		100	1985	4.22	408,892.0	3,354,573.5
SFO7		75		4.22	408,892.0	3,354,573.5
SFO5		50		4.22	408,892.0	3,354,573.5
SFO1		100	1986	3.55	408,892.0	3,354,573.5
SFO7		75		3.55	408,892.0	3,354,573.5
SFO5		50		3.55	408,892.0	3,354,573.5
SFO1		100	1987	3.57	408,892.0	3,354,573.5
SFO7		75		3.57	408,892.0	3,354,573.5
SFO5		50		3.57	408,892.0	3,354,573.5
SFO1		100	1988	2.20	408,892.0	3,354,573.5
SFO7		75		2.20	408,892.0	3,354,573.5
SFO5		50		2.20	408,892.0	3,354,573.5

Table 4-6
ISCST3 Model Predicted Maximum 1-Hour Concentrations of CO

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	UTM Location	
					East (m)	North (m)
SNG1	1-Hour	100	1984	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1985	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1986	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1987	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1988	10.30	408,892.0	3,354,573.5
SNG7		75		10.30	408,892.0	3,354,573.5
SNG5		50		10.30	408,892.0	3,354,573.5
SFO1	1-Hour	100	1984	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1985	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1986	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1987	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1988	10.30	408,892.0	3,354,573.5
SFO7		75		10.30	408,892.0	3,354,573.5
SFO5		50		10.30	408,892.0	3,354,573.5

Table 4-7
ISCST3 Model Predicted Maximum 8-Hour Concentrations of CO

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	UTM Location	
					East (m)	North (m)
SNG1	8-Hour	100	1984	3.79	408,941.9	3,354,579.0
SNG7		75		3.79	408,941.9	3,354,579.0
SNG5		50		3.79	408,941.9	3,354,579.0
SNG1		100	1985	2.77	408,892.0	3,354,573.5
SNG7		75		2.77	408,892.0	3,354,573.5
SNG5		50		2.77	408,892.0	3,354,573.5
SNG1		100	1986	4.64	408,892.0	3,354,573.5
SNG7		75		4.64	408,892.0	3,354,573.5
SNG5		50		4.64	408,892.0	3,354,573.5
SNG1		100	1987	2.98	408,892.0	3,354,573.5
SNG7		75		2.98	408,892.0	3,354,573.5
SNG5		50		2.98	408,892.0	3,354,573.5
SNG1		100	1988	2.41	408,892.0	3,354,573.5
SNG7		75		2.41	408,892.0	3,354,573.5
SNG5		50		2.41	408,892.0	3,354,573.5
SFO1	8-Hour	100	1984	3.79	408,941.9	3,354,579.0
SFO7		75		3.79	408,941.9	3,354,579.0
SFO5		50		3.79	408,941.9	3,354,579.0
SFO1		100	1985	2.77	408,892.0	3,354,573.5
SFO7		75		2.77	408,892.0	3,354,573.5
SFO5		50		2.77	408,892.0	3,354,573.5
SFO1		100	1986	4.64	408,892.0	3,354,573.5
SFO7		75		4.64	408,892.0	3,354,573.5
SFO5		50		4.64	408,892.0	3,354,573.5
SFO1		100	1987	2.98	408,892.0	3,354,573.5
SFO7		75		2.98	408,892.0	3,354,573.5
SFO5		50		2.98	408,892.0	3,354,573.5
SFO1		100	1988	2.41	408,892.0	3,354,573.5
SFO7		75		2.41	408,892.0	3,354,573.5
SFO5		50		2.41	408,892.0	3,354,573.5

Table 4-8
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM_{10}

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
A1T	Annual	100	1984	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1985	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1986	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1987	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1988	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5

Table 4-9
ISCST3 Model Predicted Maximum 24-Hour Concentrations of PM/PM_{10}

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	UTM Location	
					East (m)	North (m)
SNG1	24-Hour	100	1984	3.32	408,941.9	3,354,579.0
SNG7		75		3.32	408,941.9	3,354,579.0
SNG5		50		3.32	408,941.9	3,354,579.0
SNG1		100	1985	4.18	408,892.0	3,354,573.5
SNG7		75		4.18	408,892.0	3,354,573.5
SNG5		50		4.18	408,892.0	3,354,573.5
SNG1		100	1986	3.51	408,892.0	3,354,573.5
SNG7		75		3.51	408,892.0	3,354,573.5
SNG5		50		3.51	408,892.0	3,354,573.5
SNG1		100	1987	3.53	408,892.0	3,354,573.5
SNG7		75		3.53	408,892.0	3,354,573.5
SNG5		50		3.53	408,892.0	3,354,573.5
SNG1		100	1988	2.17	408,892.0	3,354,573.5
SNG7		75		2.17	408,892.0	3,354,573.5
SNG5		50		2.17	408,892.0	3,354,573.5
SFO1	24-Hour	100	1984	3.32	408,941.9	3,354,579.0
SFO7		75		3.32	408,941.9	3,354,579.0
SFO5		50		3.32	408,941.9	3,354,579.0
SFO1		100	1985	4.18	408,892.0	3,354,573.5
SFO7		75		4.18	408,892.0	3,354,573.5
SFO5		50		4.18	408,892.0	3,354,573.5
SFO1		100	1986	3.51	408,892.0	3,354,573.5
SFO7		75		3.51	408,892.0	3,354,573.5
SFO5		50		3.51	408,892.0	3,354,573.5
SFO1		100	1987	3.53	408,892.0	3,354,573.5
SFO7		75		3.53	408,892.0	3,354,573.5
SFO5		50		3.53	408,892.0	3,354,573.5
SFO1		100	1988	2.17	408,892.0	3,354,573.5
SFO7		75		2.17	408,892.0	3,354,573.5
SFO5		50		2.17	408,892.0	3,354,573.5

4.3.1 Comparison to PSD Significant Impact Levels and Pre-Construction Monitoring Requirements

Table 4-7 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels and the pre-construction monitoring requirements. As Table 4-7 indicates, the Project's maximum predicted concentrations are less than the PSD Class II significant impact levels (SILs) for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

Table 4-10
Comparison of Maximum Predicted Impacts with the PSD Class II Significant Impact Levels and the PSD De Minimis Monitoring Levels

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Significant Impact Level	PSD De Minimis Monitoring Level
NO_x	Annual	0.58	1	14
SO_2	Annual	0.04	1	-
	3-Hour	14.88	25	-
	24-Hour	4.22	5	13
CO	1-Hour	10.78	2,000	-
	8-Hour	4.64	500	575
PM/PM_{10}	Annual	0.04	1	-
	24-Hour	4.18	5	10

5.0 Additional and Class I Area Impact Analyses

The following sections discuss the Project's impacts on commercial, residential, and industrial growth, vegetation and soils, visibility, and nearby Class I areas.

5.1 Commercial, Residential, and Industrial Growth

The Project is at the new electrical power generating station Brandy Branch Facility near Baldwin City within Duval County. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the project.

It is anticipated that most of the labor force during the construction phase will commute from nearby communities. The electrical generating capacity created by the Project will not have a significant effect upon the industrial growth in the immediate area considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. The net number of new, permanent jobs which will be created by the Project is estimated to be six. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the proposed facility will be very small, compared to the overall population size of the surrounding area.

5.2 Vegetation and Soils

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the project's impacts on soils and vegetation will be minimal.

The NAAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation and soils. Specifically, ambient concentrations of NO_2, SO_2, CO, and PM/PM_{10} below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutants, which triggered an additional impact analysis, include NO_x,

SO_2, CO, and PM/PM_{10}. The modeled impacts were compared to the secondary NAAQS as the basis for assessing cumulative impacts. The modeling in Section 4.0 showed that the NO_x, SO_2, CO, and PM/PM_{10} impacts are below the NAAQS. The impacts are even less than the much lower significant impact level thresholds. Because the Project's emissions do not even significantly impact the NAAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Class I Area Impact Analysis

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Project is located approximately 34 km southeast and 127 km southwest of Federal PSD Class I Areas the Okefenokee Wilderness Area and Wolf Island Wilderness Area, respectively. The areas are designated as mandatory Class I areas, under the jurisdiction of the Fish and Wildlife Service as their Federal Land Manager (FLM). The FLM typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the project's impact on air the quality and visibility/regional haze.

5.3.1 Class I Air Quality Impact Analysis and Results

Air dispersion modeling was performed to determine the Project's maximum predicted impact at the Class I areas. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted impacts of NO_x, SO_2, and PM/PM_{10} at a receptor placed at the closest boundary point of the Wilderness Areas. The 5 year meteorological data set, model options, and operating scenarios used in the refined modeling analysis presented in Section 4.0, were also used in the Class I air quality impact analyses.

Tables 5-1 through 5-12 presents the results of the Class I areas air dispersion modeling for each pollutant and applicable averaging period. The maximum predicted concentrations are presented for each year and compared with the Class I SILs. The Class I SILs were calculated as 4 percent of the PSD Class I increments. As the results in Table 5-13 indicate, the maximum predicted

Table 5-1
ISCST3 Model Predicted Maximum Annual Concentrations
of NO_x at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
A1T	Annual	100	1984	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1985	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1986	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1987	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1988	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-2 ISCST3 Model Predicted Maximum Annual Concentrations of NO_x at Wolf Island						
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
A1T	Annual	100	1984	0.004	2.5	0.1
A7T		75		0.004	2.5	0.1
A5T		50		0.003	2.5	0.1
A1T		100	1985	0.004	2.5	0.1
A7T		75		0.004	2.5	0.1
A5T		50		0.003	2.5	0.1
A1T		100	1986	0.005	2.5	0.1
A7T		75		0.004	2.5	0.1
A5T		50		0.004	2.5	0.1
A1T		100	1987	0.003	2.5	0.1
A7T		75		0.003	2.5	0.1
A5T		50		0.003	2.5	0.1
A1T		100	1988	0.004	2.5	0.1
A7T		75		0.003	2.5	0.1
A5T		50		0.003	2.5	0.1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-3
ISCST3 Model Predicted Maximum Annual Concentrations
of SO_2 at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.002	2	0.08
A7T		75		0.002	2	0.08
A5T		50		0.002	2	0.08
A1T		100	1985	0.002	2	0.08
A7T		75		0.001	2	0.08
A5T		50		0.001	2	0.08
A1T		100	1986	0.002	2	0.08
A7T		75		0.002	2	0.08
A5T		50		0.001	2	0.08
A1T		100	1987	0.001	2	0.08
A7T		75		0.001	2	0.08
A5T		50		0.001	2	0.08
A1T		100	1988	0.002	2	0.08
A7T		75		0.002	2	0.08
A5T		50		0.002	2	0.08

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-4
ISCST3 Model Predicted Maximum Annual Concentrations of SO_2 at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.0010	2	0.08
A7T		75		0.0010	2	0.08
A5T		50		0.0010	2	0.08
A1T		100	1985	0.0010	2	0.08
A7T		75		0.0010	2	0.08
A5T		50		0.0004	2	0.08
A1T		100	1986	0.0007	2	0.08
A7T		75		0.0006	2	0.08
A5T		50		0.0006	2	0.08
A1T		100	1987	0.0005	2	0.08
A7T		75		0.0004	2	0.08
A5T		50		0.0004	2	0.08
A1T		100	1988	0.0005	2	0.08
A7T		75		0.0005	2	0.08
A5T		50		0.0004	2	0.08

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-5 ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2 at Okefenokee						
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
SNG1	3-Hour	100	1984	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.01	25	1
SNG1		100	1985	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.02	25	1
SNG1		100	1986	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.02	25	1
SNG1		100	1987	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1988	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.02	25	1
SFO1	3-Hour	100	1984	**1.17**	25	1
SFO7		75		**1.10**	25	1
SFO5		50		0.99	25	1
SFO1		100	1985	**1.64**	25	1
SFO7		75		**1.49**	25	1
SFO5		50		**1.29**	25	1
SFO1		100	1986	**1.19**	25	1
SFO7		75		**1.08**	25	1
SFO5		50		0.95	25	1
SFO1		100	1987	**1.13**	25	1
SFO7		75		**1.03**	25	1
SFO5		50		0.91	25	1
SFO1		100	1988	**1.98**	25	1
SFO7		75		**1.81**	25	1
SFO5		50		**1.58**	25	1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-6 ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2 at Wolf Island						
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
SNG1	3-Hour	100	1984	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1985	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1986	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1987	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1988	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SFO1	3-Hour	100	1984	0.83	25	1
SFO7		75		0.73	25	1
SFO5		50		0.62	25	1
SFO1		100	1985	0.71	25	1
SFO7		75		0.62	25	1
SFO5		50		0.52	25	1
SFO1		100	1986	0.84	25	1
SFO7		75		0.74	25	1
SFO5		50		0.64	25	1
SFO1		100	1987	<u>0.86</u>	25	1
SFO7		75		0.79	25	1
SFO5		50		0.69	25	1
SFO1		100	1988	0.45	25	1
SFO7		75		0.41	25	1
SFO5		50		0.36	25	1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-7
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO_2 at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
SNG1	24-Hour	100	1984	0.005	5	0.2
SNG7		75		0.005	5	0.2
SNG5		50		0.004	5	0.2
SNG1		100	1985	0.004	5	0.2
SNG7		75		0.004	5	0.2
SNG5		50		0.003	5	0.2
SNG1		100	1986	0.005	5	0.2
SNG7		75		0.004	5	0.2
SNG5		50		0.004	5	0.2
SNG1		100	1987	0.004	5	0.2
SNG7		75		0.004	5	0.2
SNG5		50		0.003	5	0.2
SNG1		100	1988	0.006	5	0.2
SNG7		75		0.006	5	0.2
SNG5		50		0.005	5	0.2
SFO1	24-Hour	100	1984	**0.420**	5	0.2
SFO7		75		**0.380**	5	0.2
SFO5		50		**0.320**	5	0.2
SFO1		100	1985	**0.280**	5	0.2
SFO7		75		**0.240**	5	0.2
SFO5		50		**0.210**	5	0.2
SFO1		100	1986	**0.330**	5	0.2
SFO7		75		**0.310**	5	0.2
SFO5		50		**0.280**	5	0.2
SFO1		100	1987	**0.360**	5	0.2
SFO7		75		**0.320**	5	0.2
SFO5		50		**0.270**	5	0.2
SFO1		100	1988	**0.340**	5	0.2
SFO7		75		**0.360**	5	0.2
SFO5		50		**0.330**	5	0.2

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-8
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO_2 at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
SNG1	24-Hour	100	1984	0.003	5	0.2
SNG7		75		0.003	5	0.2
SNG5		50		0.002	5	0.2
SNG1		100	1985	0.001	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SNG1		100	1986	0.001	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SNG1		100	1987	0.002	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SNG1		100	1988	0.001	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SFO1	24-Hour	100	1984	**0.220**	5	0.2
SFO7		75		**0.200**	5	0.2
SFO5		50		0.170	5	0.2
SFO1		100	1985	0.130	5	0.2
SFO7		75		0.110	5	0.2
SFO5		50		0.090	5	0.2
SFO1		100	1986	0.110	5	0.2
SFO7		75		0.010	5	0.2
SFO5		50		0.080	5	0.2
SFO1		100	1987	0.120	5	0.2
SFO7		75		0.110	5	0.2
SFO5		50		0.120	5	0.2
SFO1		100	1988	0.120	5	0.2
SFO7		75		0.100	5	0.2
SFO5		50		0.080	5	0.2

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-9
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM_{10} at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
A1T	Annual	100	1984	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1985	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1986	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1987	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1988	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.002	4	0.16

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-10
ISCST3 Model Predicted Maximum Annual Concentrations
of PM/PM_{10} at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.0004	4	0.16
A7T		75		0.0004	4	0.16
A5T		50		0.0005	4	0.16
A1T		100	1985	0.0003	4	0.16
A7T		75		0.0004	4	0.16
A5T		50		0.0004	4	0.16
A1T		100	1986	0.0004	4	0.16
A7T		75		0.0005	4	0.16
A5T		50		0.0005	4	0.16
A1T		100	1987	0.0003	4	0.16
A7T		75		0.0003	4	0.16
A5T		50		0.0004	4	0.16
A1T		100	1988	0.0003	4	0.16
A7T		75		0.0004	4	0.16
A5T		50		0.0004	4	0.16

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-11
ISCST3 Model Predicted Maximum 24-Hour Concentrations
of PM/PM_{10} at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
SNG1	24-Hour	100	1984	0.04	8	0.32
SNG7		75		0.04	8	0.32
SNG5		50		0.05	8	0.32
SNG1		100	1985	0.02	8	0.32
SNG7		75		0.03	8	0.32
SNG5		50		0.03	8	0.32
SNG1		100	1986	0.03	8	0.32
SNG7		75		0.03	8	0.32
SNG5		50		0.04	8	0.32
SNG1		100	1987	0.03	8	0.32
SNG7		75		0.03	8	0.32
SNG5		50		0.04	8	0.32
SNG1		100	1988	0.04	8	0.32
SNG7		75		0.04	8	0.32
SNG5		50		0.05	8	0.32
SFO1	24-Hour	100	1984	0.07	8	0.32
SFO7		75		0.08	8	0.32
SFO5		50		0.08	8	0.32
SFO1		100	1985	0.05	8	0.32
SFO7		75		0.05	8	0.32
SFO5		50		0.06	8	0.32
SFO1		100	1986	0.06	8	0.32
SFO7		75		0.06	8	0.32
SFO5		50		0.07	8	0.32
SFO1		100	1987	0.06	8	0.32
SFO7		75		0.06	8	0.32
SFO5		50		0.07	8	0.32
SFO1		100	1988	0.06	8	0.32
SFO7		75		0.07	8	0.32
SFO5		50		0.09	8	0.32

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-12
ISCST3 Model Predicted Maximum 24-Hour Concentrations
of PM/PM_{10} at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I Increment (μg/m³)	Class I SIL* (μg/m³)
SNG1	24-Hour	100	1984	0.02	8	0.32
SNG7		75		0.02	8	0.32
SNG5		50		0.02	8	0.32
SNG1		100	1985	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.01	8	0.32
SNG1		100	1986	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.01	8	0.32
SNG1		100	1987	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.02	8	0.32
SNG1		100	1988	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.01	8	0.32
SFO1	24-Hour	100	1984	0.04	8	0.32
SFO7		75		0.04	8	0.32
SFO5		50		0.04	8	0.32
SFO1		100	1985	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.02	8	0.32
SFO1		100	1986	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.02	8	0.32
SFO1		100	1987	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.03	8	0.32
SFO1		100	1988	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.02	8	0.32

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-13 Comparison of Maximum Predicted Impacts with the PSD Class I Significant Impact Levels			
Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class I Significant Impact Level
		Okefenokee	
NO_x	Annual	0.010	0.1
SO_2	Annual	0.002	0.08
	3-Hour	**1.980**	1
	24-Hour	**0.420**	0.2
PM/PM_{10}	Annual	0.002	0.16
	24-Hour	0.090	0.32
		Wolf Island	
NO_x	Annual	0.005	0.1
SO_2	Annual	0.001	0.08
	3-Hour	0.860	1
	24-Hour	**0.220**	0.2
PM/PM_{10}	Annual	0.001	0.16
	24-Hour	0.040	0.32

concentrations of NO_x and PM/PM_{10} are less than the applicable Class I SILs for the annual and 24-hour averaging periods, respectively, for both Class I areas. Likewise, SO_2 is also less than the applicable Class I SILs for the annual averaging period. However, SO_2 exceeds the 24-hour Class I SIL Okefenokee and the 3-hour Class I SIL for both Okefenokee and Wolf Island. A PSD increment analysis for SO_2 is warranted to show compliance.

5.3.2 PSD Class I Increment Analysis

A PSD Class I increment analysis was performed for SO_2 for 24-hour period at Okefenokee and the 3-hour period for both Okefenokee and Wolf Island Class I areas for the applicable years, fuel, and operating load since the ISC3 model predicted concentrations of SO_2 were greater than the applicable PSD Class I significant impact level.

The PSD increment is the maximum allowable increase in concentration that is allowed to occur in air quality levels at the time the baseline is set for a given pollutant. The baseline concentration, in general, is the ambient concentration existing at the time the first complete PSD permit application affecting the area is submitted.

Because Okefenokee is on the Florida state line and Wolf Island is in Georgia, FDEP was contacted regarding how to proceed with compiling the interactive source inventories from both states. Mr. Cleve Holladay at FDEP provided all PSD SO_2 increment consuming sources to be used for the analysis for both Class I areas. In addition, Mr. Holladay stated FDEP does not require a NAAQS analysis in addition to an increment analysis. The interactive for SO_2 source inventory received from FDEP on March 15, 1999 has been included as Attachment 6. As shown in Attachment 6, the interactive source inventory from FDEP contains PSD increment consuming and increment expanding sources.

The increment consuming and expanding sources provided by FDEP from the aforementioned inventory were included in the ISC3 air dispersion modeling analysis to determine the cumulative impact of these sources and the Project at each class I area for the applicable periods and loads. The model, receptor grids, meteorological data, and model options used in the previously performed modeling were also used in the multi-source interactive modeling analysis.

Table 5-14 presents the highest model predicted impacts for SO_2 for the 24-hour period at Okefenokee and the 3-hour period for both Okefenokee and Wolf Island Class I areas, with the maximum concentrations underlined. Furthermore, Table 5-14 summarizes the increment analysis by comparing the cumulative maximum predicted concentrations from

Table 5-14 ISCST3 Model Predicted Maximum Concentrations of SO_2 at for the Applicable Averaging Periods and Loads at Okefenokee and Wolf Island					
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)
Okefenokee					
SFO1	3-Hour	100	1984	16.51	25
SFO7		75		16.51	25
SFO1		100	1985	11.82	25
SFO7		75		11.82	25
SFO5		50		11.82	25
SFO1		100	1986	9.53	25
SFO7		75		9.53	25
SFO1		100	1987	10.50	25
SFO7		75		10.50	25
SFO1		100	1988	11.23	25
SFO7		75		11.23	25
SFO5		50		11.23	25
SFO1	24-Hour	100	1984	2.87	5
SFO7		75		2.87	5
SFO5		50		2.87	5
SFO1		100	1985	2.21	5
SFO7		75		2.21	5
SFO5		50		2.21	5
SFO1		100	1986	1.64	5
SFO7		75		1.64	5
SFO5		50		1.64	5
SFO1		100	1987	1.84	5
SFO7		75		1.84	5
SFO5		50		1.84	5
SFO1		100	1988	1.18	5
SFO7		75		1.16	5
SFO5		50		1.14	5
Wolf Island					
SFO1	24-Hour	100	1984	1.14	5
SFO7		70		1.14	5

the PSD interactive sources and the Project with the PSD Class I increments.

As the results indicate, the predicted concentrations are less than the applicable PSD Class I increments (i.e., the Project's ambient air quality impacts, including ambient air quality impacts from nearby increment consuming sources which impact the Project's impact area, do not exceed the PSD Class I increments).

5.4 Visibility/Regional Haze Analysis

The additional impact analysis requirements of a PSD permit application are concerned with visibility impairment within the proposed project's impact area. The general components of a visibility impairment analysis include:

- Determine the visual quality of the area.
- Determine the potential for visibility impairment with a screening level assessment.
- If warranted, conduct a more in-depth analysis of the visibility impairment potential.

5.4.1 Visual Quality of the Area

The Project is located in northeastern Florida, immediately surrounded by forest and grassland. The climate is characterized as nearly tropical with warm temperatures and abundant moisture. The high relative humidity and coastal influence generally result in moderate visibility with relatively low background visual ranges.

5.4.2 Visual Impairment Screening Assessment

A visibility impairment screening analysis was conducted in accordance with EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015, September 1988, hereinafter referred to as the Workbook), and guidance contained in the EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility (EPA-454/R-93-05, hereinafter referred to as IWAQM); April 1993, for the Class I Area located less than 50 km from the Project in order to provide a conservative indication of the perceptibility of plumes from the proposed emission source. The only Federal PSD Class I Area within 50 km is the Okefenokee Wilderness Area located approximately 34 km northwest of the Project. It should be noted, a regional haze analysis was conducted for Class I areas located at a distances greater than 50 km (see Section 5.4.2).

The analysis was performed using the VISCREEN model. In accordance with Workbook visual screening procedures and the IWAQM guidance, the VISCREEN plume visual impact screening model was used with default worst-case Level-1 visual screening parameters using the maximum estimated emission rates of NO_x and PM/PM_{10} as presented in Table 2-1.

In accordance with EPA procedures, the plume visual impact screening model (VISCREEN) was utilized with input and default parameters appropriately chosen for this geographical region. The criteria for evaluating whether there is significant visibility impairment is whether the plume from a source has the potential to be perceptible to untrained observers under reasonable worst-case conditions. The majority of input parameter values were not changed from the VISCREEN default values as specified in the Workbook. However, background visual range, stability class, and windspeed parameters have been changed to values more representative of the specific region and operating conditions of the Project, therefore producing a more realistic analysis. The situation-specific modeled values are described below:

Emissions. Table 2-1 shows the worst-case maximum hourly emissions of Nitrogen Oxide (NO_x) and Particulate Matter (PM/PM_{10}) used in the visibility analysis modeling. The worst-case maximum hourly emissions include those from the SCCTs and the diesel fire pump for each of the Project's operating scenarios.

Distances. The geometry of the Project and the Okefenokee Wilderness Area make the source-observer and minimum source distance 34 km and the maximum source distance 80 km.

Background Visual Range. A background visual range value which is considered representative of the area was based on a telephone conversation with Mr. Bud Rolofson at the Fish and Wildlife Service in Denver, Colorado on January 15, 1999. The background visual range is 65 km.

Stability Class and Windspeed. The VISCREEN stability class default value of 'F' and windspeed default value of 1.0 meter per second (m/s) were found not to be representative of the general climatological conditions of the area in the vicinity of the Project. Therefore, stability class information contained in the five years (1984-1988) of meteorological data that were used in Section 4.2 were analyzed to determine a more representative stability class. A frequency distribution for Stability Classes 1 through 7 was performed for each season of each of the five years of meteorological data. The results of the analysis show that 'D' Class stability, or neutral stability, is most common stability class contained within the five years of meteorological data. See Attachment 7 for the results of the frequency distribution.

To establish a more representative wind speed, climatological data were reviewed for this area. Windspeed values of 7.9 miles per hour (mph) (3.53 m/s) were given in the Local Climatological Data Annual Summaries for 1996, Part IV - Southern Region published by the National Oceanic and Atmospheric Administration (NOAA) for Jacksonville, Florida. This windspeed value was determined to be more representative of the windspeeds in the Project area than the VISCREEN default value of 1.0 m/s.

The VISCREEN results are provided in Attachment 7. Based on the results of this analysis the Project plume visual impact passes the Level-2 analysis specified by the Workbook for a CLASS I area. Potential visual impairment from the Project plume will not cause a notable problem or be perceptible to untrained observers. However, under certain short-term wind, meteorological, visual backgrounds, and sun angle conditions in the vicinity of the Project a plume may be detected.

The report output of the VISCREEN model is included in Attachment 7. Results of the Level-1 visual screening analysis indicate that the conservative screening criteria are not exceeded. Therefore, further analyses to quantify the extent of any reductions in visibility due to emissions from the Project are not warranted based on the results of the Level-1 visual impairment screening analysis.

5.4.3 Regional Haze Analysis

A regional haze analysis was performed in accordance with guidance published in the IWAQM document, as well as technical guidance and an example provided by the NPS to evaluate the potential for visibility impairment (significant increase in uniform haze) at the Wolf Island Wilderness area. The Okefenokee Wilderness Area was not assessed because its closest boundary is less than 50 km from the project as described in the IWAQM document. Visibility impairment occurs as a result of the scattering and absorption of light due to particles and gasses in the atmosphere. On a local-scale, visual impairment is generally defined as a plume or layered haze from a single source or small group of sources. This phenomena, known as regional haze, impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. The methodology, input, and results are described in the following subsections.

5.4.3.1 Analysis Methodology and Input. The reduction of image forming light per unit distance in the atmosphere due to the sum of scattering (light redirected away from the sight path) and adsorption (light captured by aerosols and turned into heat energy) is represented by a term known as the extinction coefficient (b_{ext}). Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level (usually set at 2% difference between target and sky), a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere. With the aforementioned assumptions, extinction can be related to visual range with the following equation:

$$b_{ext} = \frac{3.912}{vr}$$

Where: b_{ext} = extinction coefficient, 1/km
vr = visual range, km

A uniform incremental change in b_{ext} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a change in b_{ext}, or; percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, the Level I screening analysis is satisfied, and no further analysis is required. The percent change in extinction is calculated as follows:
Where: b_{exts} = source extinction coefficient

$$= \frac{b_{exts}}{b_{extb}}(100\%)$$

b_{extb} = background extinction coefficient

The source extinction coefficient is calculated as a function of the source's NO_x and fine PM model predicted concentration levels at the Class I area, as well as the ambient relative humidity. Although relative humidity does not by itself cause visibility to be degraded, some particles in the atmosphere accumulate water and grow to just the right size to be very efficient at scattering light. Based on guidance from the IWAQM document and NPS, the source extinction coefficient may be calculated as follows:

$$b_{exts} = (0.003)(RH_f)[(NH_4)_2SO_4 + NH_4NO_3] + (0.003)(PM_{fine})$$

Where: RH_f = relative humidity correction factor to adjust for the effects of ambient humidity on light extinction calculations.

NH_4NO_3 = concentration of ammonium nitrate in units of $\mu g/m^3$, calculated as (NO_x 24-h concentration, $\mu g/m^3$)(1.35)(1.29), assuming all NO_x converts to ammonium nitrate.

$(NH_4)_2SO_4$= concentration of ammonium sulfate in units of $\mu g/m^3$, calculated as (SO_2 24-h concentration, $\mu g/m^3$)(1.5)(1.375), assuming all SO_2 converts to ammonium sulfate.

PM_{fine}= concentration of primary fine particulate in units of $\mu g/m^3$, calculated as (PM/PM_{10} 24-h concentration, $\mu g/m^3$)(1.0), assuming all PM/PM_{10} is primary fine particulate.

The background extinction coefficient is calculated as a function of the estimated visual range as follows:

$$b_{extb} = \frac{3.912}{vr}$$

Where: b_{extb} = background extinction coefficient, 1/km

vr = background visual range, km

5.4.3.2 Regional Haze Calculations and Results. Based on the aforementioned methodology, the percent change in extinction for normal SCCT operation and 5 years of meteorological data was assessed in the refined modeling analysis presented in Section 4.0. The results of the analysis are presented in a spreadsheet included as Attachment 8. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted 24-hour impacts of NO_x, SO_2, and PM/PM_{10} at a receptor placed at the closest boundary point of the Wilderness Area. Actual relative humidity data corresponding to the date of the maximum predicted NO_x and SO_2 impacts for each scenario were used in the regional haze calculations.

As the results in Attachment 8 indicate, the maximum percent change in extinction for all five years of 3 percent is less than screening threshold for Level I analyses of 5 percent. Therefore, further analysis of potential visibility impairment is not warranted.

Attachments

Attachment 1
(Turbine Vendor Data)

JEA - Inlet Bleet Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.

EMISSIONS

NOx	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen	74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen	12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide	3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water	8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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JEA - Inlet Bleed Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.
EMISSIONS									
NOx	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen		74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen		12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide		3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water		7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

IPS- 70600 version code- 1 . 4 . 1 Opt: 10
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JEA - Inlet Bleed Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.
EMISSIONS									
NOx	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen		72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen		12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide		3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water		10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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Attachment 2
(Tanks Model Output)

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification

Identification No.:	
City:	Brandy Branch
State:	FL
Company:	JEA - F.O. Storage Tanks
Type of Tank:	Vertical Fixed Roof
Description:	Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft):	40.0
Diameter (ft):	65.6
Liquid Height (ft):	39.8
Avg. Liquid Height (ft):	20.0
Volume (gallons):	1000000
Turnovers:	11.1
Net Throughput (gal/yr):	11100000

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	56.00
Slope (ft/ft) (Cone Roof):	0.0000

Breather Vent Settings

Vacuum Setting (psig):	-0.03
Pressure Setting (psig):	0.03

Meteorological Data Used in Emission Calculations: Jacksonville, Florida (Avg Atmospheric Pressure = 14.7 psia)

Basis for Vapor Pressure Mixture/Component Calculations	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight
Distillate fuel oil no. 2 Option 3: A=12.1010, B=8907.0	All	69.94	64.36	75.52	68.02	0.0089	0.0075	0.0107	130.000			188.00

Annual Emission Calculations

Standing Losses (lb):	243.2499
Vapor Space Volume (cu ft):	86154.41
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.038277
Vented Vapor Saturation Factor:	0.988064
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	86154.41
Tank Diameter (ft):	65.6
Vapor Space Outage (ft):	25.49
Tank Shell Height (ft):	40.0
Average Liquid Height (ft):	20.0
Roof Outage (ft):	5.49
Roof Outage (Dome Roof)	
Roof Outage (ft):	5.49
Dome Radius (ft):	56
Shell Radius (ft):	32.8
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Daily Avg. Liquid Surface Temp.(deg. R):	529.61
Daily Average Ambient Temp. (deg. R):	527.67
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	527.69
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqft□day):	1438.00

Vapor Space Expansion Factor

Vapor Space Expansion Factor:	0.038277
Daily Vapor Temperature Range (deg.R):	22.32
Daily Vapor Pressure Range (psia):	0.003180
Breather Vent Press. Setting Range(psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.007476
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.010655
Daily Avg. Liquid Surface Temp. (deg R):	529.61
Daily Min. Liquid Surface Temp. (deg R):	524.03
Daily Max. Liquid Surface Temp. (deg R):	535.19
Daily Ambient Temp. Range (deg.R):	21.50

Annual Emission Calculations	
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.988064
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Space Outage (ft):	25.49
Working Losses (lb):	307.2093
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Annual Net Throughput (gal/yr):	11100000
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	134518
Maximum Liquid Height (ft):	39.8
Tank Diameter (ft):	65.6
Working Loss Product Factor:	1.00
Total Losses (lb):	550.46

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Working	Total
Distillate fuel oil no. 2	243.25	307.21	550.46
Total:	243.25	307.21	550.46

□

Attachment 3
(Emission Calculation Spreadsheet)

JEA
Jacksonville, Florida
Enveloped Stack Parameters

60903 0030

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 03/22/99 02.11 PM

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	100 Percent							100 Percent								
Turbine	PG7241 (FA)			Representative'		59 Degrees		PG7241 (FA)			Representative'		59 Degrees			
Ambient Temperature (F)	95	59	--	100 Pecent Load		100 Pecent Load		95	59	20	100 Pecent Load		100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	147.76	156.75	164 0	147.76 ft/s	45 04 m/s	156.75 ft/s	47.78 ft/s	151 8	161 8	168.04	151.8 ft/s	46.27 m/s	161 60 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1144	1116	1081	1081 F	855 93 K	1116.00 F	875.37 K	1133	1098	1068	1068 F	848 71 K	1098 00 F	865.37 K	1116 00 F	875.37 K
Emissions (lb/h)																
NOx (f)	71 20	79.20	84 80	84 8 lb/h	10.68 g/s	36.16 lb/h	4 56 g/s	286.00	318 00	338.00	338 lb/h	42.58 g/s	29 04 lb/h	3 66 g/s	65 21 lb/h	8.22 g/s
CO	43.00	48 00	52.00	52 lb/h	6.55 g/s	21.92 lb/h	2.76 g/s	59 00	65 00	69.00	69 lb/h	8.69 g/s	5 94 lb/h	0 75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	0 97	1.07	1.14	1.14 lb/h	0 14 g/s	0 49 lb/h	0 06 g/s	88.38	96.21	104.30	104.3 lb/h	13.14 g/s	8 97 lb/h	1.13 g/s	9 46 lb/h	1 19 g/s
PM (b)	9.00	9.00	9 00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17 00	17 00	17.00	17 lb/h	2.14 g/s	1 55 lb/h	0.20 g/s	5 66 lb/h	0 71 g/s
VOC (c)	2.60	2.80	3 00	3 lb/h	0 38 g/s	1.28 lb/h	0.16 g/s	2 60	3 00	3 00	3 lb/h	0.38 g/s	0.27 lb/h	0 03 g/s	1.55 lb/h	0.20 g/s

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	75 Percent							75 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees		PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load		95	59	20	75 Pecent Load		75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	124.17	129 71	133.13	124.17 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s	128 43	131 67	135 15	126 43 ft/s	38.54 m/s	131 67 ft/s	40.13 m/s	129.71 ft/s	39 54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873 15 K	1139 00 F	886.15 K	1200	1194	1183	1183 F	912.59 K	1194 00 F	918 71 K	1139 00 F	888.15 K
Emissions (lb/h)																
NOx (f)	58 40	63.20	67.20	67.2 lb/h	8 47 g/s	28 86 lb/h	3 64 g/s	232 00	256 00	271.00	271 lb/h	34.14 g/s	23 38 lb/h	2.95 g/s	52.24 lb/h	6 58 g/s
CO	36 00	39 00	41 00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s	47.00	50 00	51 00	51 lb/h	6 43 g/s	4 57 lb/h	0 58 g/s	22.37 lb/h	2 82 g/s
SO2 (a)	0.79	0 86	0 92	0 92 lb/h	0 12 g/s	0 39 lb/h	0.05 g/s	72 32	79.89	84 44	84 44 lb/h	10 64 g/s	7.28 lb/h	0 92 g/s	7.67 lb/h	0 97 g/s
PM (b)	9 00	9 00	9 00	9 lb/h	1.13 g/s	4 11 lb/h	0 52 g/s	17 00	17 00	17 00	17 lb/h	2.14 g/s	1 55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0 30 g/s	1 00 lb/h	0.13 g/s	2.20	2.2	2.4	2 4 lb/h	0.30 g/s	0.20 lb/h	0 03 g/s	1.21 lb/h	0 15 g/s

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	50 Percent							50 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees		PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load		95	59	20	50 Pecent Load		50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	106 35	110.53	112 68	106.35 ft/s	32 42 m/s	110 53 ft/s	33 69 m/s	108 45	112.04	113 42	108.45 ft/s	33 06 m/s	112 04 ft/s	34 15 m/s	110.53 ft/s	33 69 m/s
Exit Temp (F)	1200	1184	1160	1160 F	899.82 K	1184 00 F	913 15 K	1200	1200	1200	1200 F	922 04 K	1200 00 F	922.04 K	1184 00 F	913 15 K
Emissions (lb/h)																
NOx (f)	46 40	50 40	52.80	52.8 lb/h	6.65 g/s	23 01 lb/h	2.90 g/s	182 00	199 00	209 00	209 lb/h	26.33 g/s	18 17 lb/h	2.29 g/s	41.18 lb/h	5 19 g/s
CO	30.00	33 00	34.00	34 lb/h	4.28 g/s	15 07 lb/h	1 90 g/s	74.00	63 00	57 00	74 lb/h	9 32 g/s	5 75 lb/h	0 72 g/s	20.82 lb/h	2 62 g/s
SO2 (a)	0.64	0 69	0 73	0 73 lb/h	0.09 g/s	0.32 lb/h	0 04 g/s	57 30	62 70	65 90	65.9 lb/h	8 30 g/s	5 73 lb/h	0 72 g/s	6.04 lb/h	0 76 g/s
PM (b)	9.00	9 00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17 00	17 00	17 00	17 lb/h	2 14 g/s	1 55 lb/h	0.20 g/s	5 66 lb/h	0 71 g/s
VOC (c)	1.80	1 80	2 00	2 lb/h	0.25 g/s	0 82 lb/h	0.10 g/s	1 80	1.80	2 00	2 lb/h	0 25 g/s	0 16 lb/h	0 02 g/s	0.99 lb/h	0 12 g/s

NOTE:

(a) SO2 values were calculated based on 0 2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23 8 ft^3)*(20 675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639 4 MBtu/hr)*(10^6 BTU/MBtu) = 88 38 lb/hr.
(b) PM emission values are for front half filterable emissions only.
(c) VOC emissions represent 20% of the UHC emissions.
(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.
(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.
(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.

Annual Potential to Emit Calculations (59 F)

Pollutant	Maximum Emission Rates Natural Gas SCCT (lb/hr)	Maximum Emission Rates Fuel Oil SCCT (lb/hr)	Fire Pump (lb/hr)	Single SCCT (tpy)	Fire Pump (tpy)	Facility Total (tpy)	PSD SEL (tpy)	Exceed SEL (yes/no)	
NOx	79.2	318	11.7	285.6	0.304	857.7	40	yes	NOx
CO	48	65	2.5	122.0	0.065	366.2	100	yes	CO
SO2	1.07	98.21	0.8	41.4	0.021	124.3	40	yes	SO2
VOC	2.8	3	0.9	6.8	0.023	20.5	40	no	VOC
PM/PM10	9	17	0.8	24.8	0.021	74.5	15	yes	PM/PM10
H2SO4	0.13	11.98	0.1	5.1	0.003	15.2	7	yes	H2SO4
Total Reduced Sulfur (TRS)	negl.					negl.	10	no	TRS
Hydrgen Sulfide (H2S)	negl.					negl.	10	no	H2SO4
Vinyl Chlorides (VC)	negl.					negl.	1	no	VC
Total Flourides (TF)	negl.					negl.	3	no	TF
Arsenic (As)	negl.	8.93E-03				negl.		no	As
Mercury (Hg)	negl.	1.66E-03				negl.	0.1	no	Hg
Beryllium (Be)	negl.	6.01E-04				negl.	0.0004	no	Be
Lead (Pb)	negl.	0.106				0.042	0.6	no	Pb

3 # of turbines
4000 hours of natural gas simple cycle operation per year
800 hours of fuel oil simple cycle operation per year
52 hours of diesel fire pump operation per year

Notes:

a Worst Case emissions are from 100, 75, and 50% loads for one vendor at 59 F.
b SO2 emissions are based on 0.2 gr/100 scf sulfur in the natural gas for the simple cycle turbines and #2 distillate fuel oil (0.05% sulfur) for the fuel oil simple cycle turbines.
c H2SO4 based on a 10% conversion of SO2 to SO3 and a molecular ratio of 1.22 from SO3 to H2SO4.
d Trace element emission rates were calculated using AP-42 emission factors (Table 3.1-4) and a worst case heat input between 100, 75, and 50% loads @ 59F (NG=1,622.9 MBtu/hr & FO=1,821.8.0 MBtu/hr).
e VOC emissions represent 20% of the UHC emissions from 100, 75, and 50% loads for one vendor at 59 F.
f Diesel fire pump emissions were calculated using AP-42 emission factors (Table 3.3-1) and were based on an assumed diesel fire pump size of 125 BHP (~379 hp assuming 33% efficiency).
g PM/PM10 emissions are for front half only.
h NOx emissions are based on 12 ppm for natural gas and 42 ppm for fuel oil.

i

	AP-42 Emission Factors (oil)	
As	4.90E-06	lb/MBtu
Hg	9.10E-07	lb/MBtu
Be	3.30E-07	lb/MBtu
Pb	5.80E-05	lb/MBtu

Attachment 4
(Best Available Control Technology)

Best Available Control Technology Analysis

The Brandy Branch Project

Prepared for: Jacksonville Electric Authority

Prepared by: Black & Veatch

Executive Summary

A BACT analysis was performed for three (3) new General Electric 7FA combustion turbines to be installed at the Brandy Branch Project. The combustion turbines are to be operated as simple cycle combustion turbines (SCCT), i.e. without heat recovery steam generators, to allow faster response time to changing load demands. The following was evaluated to be BACT for the following emissions parameters for each SCCT.

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners during natural gas firing and water injection for fuel oil firing to achieve the following emission limits.

- Burning natural gas at unit loads between 50 percent and 100 percent of normal capacity, an emission limit of 12 ppmvd (referenced to 15 percent O_2).
- Burning fuel oil at load between 50 and 100 percent of normal capacity, an emission limit of 42 ppmvd (referenced to 15 percent O_2).

Carbon monoxide (CO) emissions--Good combustion controls to achieve a CO emission limit of 15 ppmvd during natural gas firing or 20 ppmvd during fuel oil firing.

Particulate emissions--Good combustion controls.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)--Good combustion controls using natural gas and fuel oil with less than 0.5 percent sulfur.

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1.0 Introduction

The 1977 Clean Air Act established revised conditions for the approval of pre-construction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the act emitted in significant amounts from new major sources or modifications. The new major sources proposed for this project include three combustion turbines and a diesel generator that are subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this project.

2.0 BACT Analyis Basis

This section describes the basis of this BACT analysis. Information is provided on such issues as the project description, BACT methodology and approach used, and the parameters and factors used in developing the analysis are identified.

2.1 Project Description

The Brandy Branch Project will consist of the installation of three General Electric 7FA combustion turbine electric generating units. Each combustion turbine unit will consist of one turbine and one generator operating as simple cycle combustion turbines (SCCT). The output rating for each of the new units will be nominally 172.6 MW net while firing gas. Total plant output will be nominally 517.8 MW.

The combustion turbines will fire natural gas as the primary fuel and No. 2 fuel oil as an emergency back-up fuel. The proposed operating scenario for the combustion turbines includes limiting the firing of natural gas to 12,000 hour per year for the facility (equivalent to a per unit operation of 4,000 hours per year) and limiting firing of No. 2 fuel oil to no more than 2,400 hours per year for the facility (equivalent to a per unit operation of 800 hours per year).

2.2 BACT Methodology

As defined in the air permit application, operation of the Project will result in an increase in the potential to emit emissions of NO_x, CO, PM/PM_{10}, and SO_2/Sulfuric Acid Mist (SAM); in excess of the major modification PSD threshold levels set for these pollutants. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (dated March 15, To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (dated March 15, 1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. Technologies required under Lowest Achievable Emission Rate (LAER) determinations must be considered. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

Economic analysis used to determine the capital and annual costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA BACT Guidelines, The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fourth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

2.3 Economic Basis

Table 2-1 lists the economic criteria used in the analysis of BACT alternatives.

Table 2-1
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	20
Real Interest Rate, percent	8.00
Economic Life years	20
Labor Cost, $/man-yr	60,000
Anhydrous Ammonia Cost, $/ton (1999)	230
Energy Cost, $/kWhr (1999)	.0221
Catalyst Life, years	3

3.0 BACT Analysis Basis

The BACT analysis for the SCCT units is based on certain regulatory requirements and project assumptions.

The following is a summary of the requirements and assumptions for which this BACT analysis is based:

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal NSPS for combustion turbines with heat input greater than 10 mmbtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for SO_2 and NO_x emissions only. No NSPS criteria have been established for limiting CO, VOC, and PM/PM_{10} emissions. The following flue gas emission limits are established by NSPS for Subpart GG units:

  NO_x: 75 ppmvd at 15 percent O_2, corrected for fuel nitrogen content and turbine heat rate.

- The combustion turbine will have the following emission rates at 100 percent load:

	Natural gas	Fuel Oil
NO_x, ppmvd @ 15% O_2:	12	42
CO, ppmvd:	15	20
PM/PM_{10}, lb/mmbtu: (front half catch only)	0.0055	0.0093
SO_2, lb/hr	1.07	98.21

The proposed operating scenario for the combustion turbines includes limiting the firing of natural gas to 12,000 hour per year for the facility (equivalent to a per unit operation of 4,000 hours per year) and limiting firing of No. 2 fuel oil to no more than 2,400 hours per year for the facility (equivalent to a per unit operation of 800 hours per year).

4.0 NO_x BACT

The objective of this analysis is to determine BACT for NO_x emissions from the combustion turbines. Unless otherwise noted the NO_x emission rates described in this section are corrected to 15 percent oxygen.

4.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents (CAPCOA, 1985-1992; USEPA, 1990 to present) indicates that the most stringent NO_x emissions limit for a natural gas fired CT is 3.0 ppmvd for the Sacramento Power Authority located in California. The emissions from that unit are controlled through the use of standard combustors and selective catalytic reduction (SCR). This unit is a combined cycle combustion turbine (CCCT) as compared to the simple cycle combustion turbine proposed for the Project. It should be noted that this combustion turbine is located in a non-attainment area for ozone, with NOx regulated as a non-attainment pollutant. Thus, this emission level represents LAER for CCCT.

For SCCT units, the strictest emission limit identified during the review is 5 ppm. This limit has been set for three different projects in California. These projects are the Southern California Gas Wheeler Ridge Gas plant located in the San Joaquin Valley, the Carson Energy Project in metropolitan Sacramento, and the Sacramento Power Authority Proctor and Gamble plant in metropolitan Sacramento. A summary of recent BACT/LAER determinations is provided in Appendix A.

It should also be noted that recently the South Coast Management District in California has officially declared new LAER limits for NO_x. This designation is limited to only specific application of CCCT projects and is not considered applicable to this Project as will be discussed.

Review of previous State of Florida DEP permits indicates that combustion turbine permits approved in the last 4 years have NO_x emission limits that vary from 15 to 9 ppmvd. The Oleander Power Project was recently granted a permit (Air Permit No. PSD-FL-258) during 1999 which limits NO_x emissions to 9 ppmvd when firing natural gas. Review of the permit conditions appear to indicate that fuel oil firing at 42 ppmvd will approach or equal the natural gas firing. The primary fuel proposed at Brandy Branch is natural gas.

4.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. Emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NOx and are a function of combustion temperature. NOx production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NOx-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxides control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NOx formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NOx emissions required. The different types of emission controls reviewed by this BACT analysis are as noted below.

In Combustor Type:

- Water/Steam Injection
- Dry Low NO_x Burners
- Xonon

Post Combustion Type:

- SNCR
- SCR
- SCONOX

4.2.1 Water or Steam Injection

NO_x emissions from the combustion turbines can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. However, there is a point at which the amount of water injected into the combustion turbine seriously degrades its reliability and operational life. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions which are formed as a result of incomplete combustion.

The development of dry low-NO_x burners has replaced the use of wet controls except for certain cases such as oil firing. The use of water injection will be considered for operations when oil firing.

4.2.2 Dry Low NO_x Burners

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called dry low NO_x burners, because when firing fuel, no water needs to be injected into the combustion chamber to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion systems as the state of the art for NO_x controls in combustion turbine.

DLN combustion turbine burner designs are available which uses improved air/fuel mixing and reduced flame temperatures to limit thermal NO_x formation. DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process ensures good mixing of the air and fuel and minimizes the amount of air required, which results in low NO_x emissions. However, during fuel oil firing, dry low NO_x burners have not achieved emissions as low as with natural gas.

Also, as with the standard combustor with water injection, the dry low NO_x burners can also be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures will result in higher CO and VOC emissions.

4.2.3 XONON

Another form of in-combustor control is Xonon. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2700 F at full power generation, which significantly reduces NOx emissions without raising and possibly even lowering emissions of carbon monoxide and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This technology is being commercialized by several joint ventures that Catlaytica has with turbine manufacturers. To date, commercialization of this technology on utility size CTs such as proposed for the Project has not been developed.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. However, the exhaust temperature at the exit of a combustion turbine, which ranges from 1,000 to over 1,200 for these CT units, is too low for any consideration of this technology. Temperatures in the range of 1,500-1,900 °F, along with adequate reaction time at this temperature range, are required to use this technology.

4.2.5 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CCCT projects for the past 5 years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades ammonia slip will increase to approximately 10 ppm, ultimately requiring catalyst replacement.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadia/titania catalysts have been used on the vast majority of SCR system installations (greater than 95 percent). The optimum flue gas temperature range for SCR operation using a conventional vanadia/titania catalyst is approximately 600 to 750 F. At temperatures above 800 F permanent damage to the vanadia/titania catalyst occurs. For the simple cycle turbines proposed for the Project, this temperature window does not exist. Flue gas from a SCCT will typically range from 1,050 F to 1,200 F. Accordingly, a vanadia/titania catalyst can not be installed at a simple cycle facility. Therefore, the vanadia/titania based catalyst will not be evaluated further for these units.

However, another catalyst material has been developed to which has had mixed success in limited application experiences. This catalyst uses zeolites, which can operate effectively at temperatures of up to 1,125 F, as the principle catalytic material. Zeolites, which are crystalline aluminasilicate compounds, do not contain materials classified as hazardous. Therefore, it is possible that these SCR catalysts can be disposed of by landfilling provided that contamination does not occur during SCR operation. Disposal would be subject to state and local regulations. Since zeolites have the most limited use of SCR catalysts, disposal requirements have not been adequately established. Zeolite based catalyst is significantly more expensive than the vanadia/titania based catalyst. In addition, the durability and effectiveness of zeolites in commercial SCR applications does not have a long history base.

Due to the high flue gas exit temperatures of the GE 7FA that can exceed 1200 F, the use of a zeolite catalyst would even require special precautions and equipment additions. As previously indicated, the maximum operating temperature of the catalyst is 1,125 F. To prevent damage to the catalyst at the higher temperatures a dilution air system and fan would need to be included for each unit to cool the flue gas to less than the maximum operating temperature of the catalyst. This analysis will include a dilution system in the evaluation of a zeolite SCR.

The operation of zeolite catalyst on sulfur bearing fuel fired units, such as oil fired units, also has very limited experience. In addition, the operation of a SCR on units that burn sulfur-bearing fuels will present a negative impact on the environmental performance of combustion turbine units. The environmental impact is due to the reaction of the excess ammonia that passes through the SCR with the sulfur trioxide (SO3) in the flue gas to form ammonia-sulfur salts, such as ammonium bisulfate. These compounds will form when the flue gas cools upon leaving the stack as a fine particulate that adds to the emissions of PM10 from the unit. This PM10 contributes to increased opacity from the unit, increased contribution to regional haze, and additional health risks. Previous regulating authorities have recognized these negative impacts and provided permit exemptions for operating the SCR during fuel oil firing.

This method of post-combustion control will be considered in this BACT analysis to control NO_x emissions when firing natural gas only.

4.2.6 SCONOX

A third, relatively new post-combustion technology is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NOx and CO. Based on this technology, the South Coast Management District recently declared LAER as 2.0 ppm of NO_x. However because the SCONOx catalyst is sensitive to SO2 concentrations and the catalyst is required to operate in temperature range between 550 F and 650 F, this technology is not applicable to the Project due to the simple cycle unit operation and fuel oil firing. This method of post-combustion control will not be considered in this BACT analysis.

4.2.7 Technology Summary

The following control technologies will be evaluated in this NO_x BACT analysis and are ranked in order of relative control effectiveness:

- The addition of zeolite catalyst SCR systems to reduce outlet emissions from each combustion turbine to 5.0 ppmvd during natural gas firing (LAER).
- In-combustor NO_x control consisting of dry low NO_x combustors to limit outlet emissions during natural gas firing to 12 ppmvd and water injection to limit outlet emissions to 42 ppmvd during fuel oil firing for all operating loads.

The NO_x emissions for a GE 7FA unit are summarized in Table 4-1.

4.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenarios evaluated.

4.3.1 Economic Impacts

The use of SCR has significant economic impact to the Project. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating the combustion turbine at full load for 4,000 hours per year on natural gas and 800 hours per year on No. 2 fuel oil.

4.3.1.1 Capital and Operating Costs.

Table 4-2 presents the capital costs for installing an SCR system on the General Electric 7FA combustion turbines to achieve a NO_x outlet emission level of 5.0 ppmvd (LAER) during natural gas firing. Consideration for design requirements for lowering the NO_x emission from 42.0 ppmvd during fuel oil firing were not included for the oil firing case due to its limited operating time, negative environmental impacts, and the uncertainty of its effectiveness while firing oil. The cost of the SCR system includes the ammonia receiving, storage, transfer,

Table 4-1 Estimated NO_x Emissions From Alternate Control Technologies Per General Electric 7FA		
Fuel	Control Technology Alternatives	
	Dry Low NO_x Combustors (Gas) - Water Injection (Oil)	SCR System
Natural Gas		
ppmvd (at 15% O_2)	12	5
Tons per year[a]	158.4	66
Fuel Oil		
ppmvd (at 15% O_2)	42	42
Tons per year[b]	127.2	127.2
BACT Analysis (Annual)[c]		
Tons per year	285.6	193.2

Notes:

[a] Annual emissions are based on 4,000 hours of operation per year at full load rating with an ambient temperature of 59 degree F..

[b] Annual emissions are based on 800 hours of operation per year at full load rating with an ambient temperature of 59 degree F.

[c] BACT analysis total emissions are based on 4,000 hours per year of natural gas firing and 800 hours per year of No. 2 fuel oil firing.

Table 4-2
NO_x Control Alternative Capital Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts	1,556,000	NA	Scaled from previous projects
Catalyst Reactor	205,000	NA	Estimated
Control/Instrumentation	140,000	NA	Estimated
Dilution Air System	282,000	NA	Estimated for entire fan system
Ammonia Injection / Storage	290,000	NA	Scaled from previous projects
Balance of Plant	841,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering.
Total Direct Capital Cost	3,314,000	Base	
Indirect Capital Costs			
Contingency	663,000	NA	20% of Direct Capital Cost
Engineering and Supervision	331,000	NA	10% of Direct Capital Cost
Construction & Field Expense	166,000	NA	5% of Direct Capital Cost
Construction Fee	331,000	NA	10% of Direct Capital Cost,
Start-up Assistance	66,000	NA	2% of Direct Capital Cost
Performance Test	46,000	NA	Estimated Cost
Total Indirect Capital Costs	1,603,000	Base	
Total Installed Cost	4,916,000	Base	

Table 4-3
NO_x Control Alternative Annual Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1.
Catalyst Replacement	327,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	21,000	NA	See text for background information on this item
Reagent Feed	17,000	NA	Assumes 1.10 stoichiometric ratio
Power Consumption	30,000	NA	Includes dilution air fan
Lost Power Generation	34,000	NA	Back pressure on combustion turbine
Annual Distribution Check	17,000	NA	Required for SCR
Total Direct Annual Cost	446,000	NA	
Indirect Annual Costs			
Overhead	7,000	NA	60% of O&M Labor
Administrative Charges	98,000	NA	2% of Total Installed Cost
Property Taxes	135,000	NA	2.75% of Total Installed Cost
Insurance	49,000	NA	1% of Total Installed Cost
Capital Recovery	501,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	790,000	NA	
Total Annual Cost	**1,236,000**	NA	
Annual Emissions, tpy	193.2	285.6	Emissions taken from Table 4-1for oil firing
Emissions Reduction, tpy	92.4	NA	Emissions calculated from Table 4-1
Total Cost Effectiveness, $/ton	**13,380**	NA	Total Annual Cost/Emissions Reduction

vaporization, and injection; catalytic reactor; and balance of plant equipment. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the catalyst material were based on zeolite catalysts.

Table 4-3 presents the annual operating costs and emission rates using SCR to achieve NO_x outlet emissions of 5.0 ppmvd while firing natural gas. Annual operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent, and heat rate penalty. Throughout the life of the plant, catalyst elements will require periodic replacement. As the catalyst becomes deactivated, ammonia slip emissions will increase. At the point ammonia slip approaches 10 ppmvd the catalyst must be replaced. Currently, catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours) for the zeolite catalyst. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.10 for reacting NO. This higher stoichiometric ratio allows for the higher molar ratio of ammonia required to react with the NO_2. The heat rate penalty cost item reflects the cost due to the SCR back pressure losses. The additional back pressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annual cost estimate.

The use of an SCR system increases the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the anhydrous ammonia reagent for injection. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the Project. Maintenance costs consist of routine SCR system maintenance. The replacement materials are assumed to be two percent of the original cost for equipment and labor is assumed to be equal to materials.

Total 1999 annual costs for the NO_x control system are calculated as the sum of 1999 operating costs plus capital recovery factor. The total annual cost per unit for a 5.0 (gas)/42.0 (oil) ppmvd NO_x outlet emission SCR system for the 7FA combustion turbines is estimated to be $1,236,000. This annual cost results in a cost effectiveness per ton of NO_x removed of approximately $13,380.

4.3.1.2 Energy Impacts.

The use of an SCR system impacts the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the anhydrous ammonia reagent for injection. In addition, an SCR system catalyst will increase the back pressure on each combustion turbine. The SCR system will add 1.5 inches water gauge (in. w.g.) back pressure to each type of unit. This will reduce the output of each combustion turbine by approximately 0.19 percent. Increased power consumption and lost power generation are included in the annual cost estimate.

4.3.1.3 Environmental Impacts.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes. With proper precautions, anhydrous ammonia can be stored and used safely.

Some ammonia slip from the combustion turbine stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd (uncorrected), unless that limit is shown to be inappropriate. At least one air pollution control district in California recently set an ammonia slip emissions limit of 10 ppmvd (uncorrected). Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates associated catalyst replacement. A design value of 10 ppmvd (uncorrected) is appropriate for a clean fuel facility such as this Project. With fresh catalyst ammonia slip emissions will be very low. However, as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

Over time, with exposure to trace elements in the flue gas, SCR catalysts can become contaminated and, depending on the type of contamination, may be classified as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

When firing fuel oil or any sulfur bearing fuel, the SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600 F the ammonia present in the flue gas may react with the SO_3 to form ammonium sulfate and bisulfate salts. This may formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge since this temperature will only be reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. This particulate will predominately consist of matter less than 10 microns in diameter (PM_{10}).

4.4 Conclusions

SCR systems are representative of the LAER level of NO_x emissions reduction. SCR systems have been successfully used on numerous combined cycle combustion turbine applications but have limited experience mixed results on SCCT applications. The fundamental obstacle to the use of these systems on a SSCT is the overall economics and the potential primary (SO_2 to SO_3 oxidation) and secondary (ammonium bisulfate deposits and increased PM_{10} emissions) environmental impacts when firing sulfur bearing fuels. NO_x reduction costs for the proposed turbines are $13,380 per ton of removed NO_x. This overall annual cost of the SCR to meet NO_x emission limits of 5.0 ppmvd (natural gas firing) and 42.0 ppmvd (fuel oil firing) is judged to be excessive. In addition, SCR use will result in additional PM_{10} emissions caused by the additional SO_2 to SO_3 oxidation and associated ammonium bisulfate/sulfate and H_2SO_4 emissions. Therefore, based on energy, environmental, and economic impacts, the use of dry low NO_x combustors to meet an emissions level of 12 ppmvd during natural gas firing and water injection to meet an emission limit of 42 ppmvd during fuel oil firing is recommended as BACT for the proposed General Electric 7FA combustion turbines. This proposed limit is considered consistent with the range of emission limits allowed for other recent permits allowed in the U.S. and the State of Florida.

5.0 CO BACT

The objective of this analysis is to determine BACT for CO emissions from the combustion turbines.

5.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a combustion turbine is 1.8 ppmvd at 15 percent O_2 for the Newark Bay Cogeneration L.P. project located in New Jersey. These emissions are achieved by reducing CO emissions through the use of an oxidation catalyst. It should be noted that the Newark Bay project is located in non-attainment areas for CO and ozone (VOC control required) and therfore represents LAER. A summary listing of recent BACT determinations is presented in Appendix A.

Recent applications in the State of Florida include the City of Tallahassee (25 ppm on gas and 90 ppm on oil), the FPC Hines project (25 ppm on gas and 30 ppm on oil), and the Tiger Bay project (15 ppm on gas and 30 ppm on oil).

5.2 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO. CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures through steam/water injection or staged combustion, which is used to reduce combustor based NO_x formation, can be counterproductive with regard to CO emissions.

The only CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic. No reagent injection is necessary and oxidizing catalysts are capable of reducing CO emissions by up to 90 percent. The already very low emissions on the 7FA machine of 15 ppm is expected to limit any additional emissions reductions on gas firing to 1.8 ppmvd @ 15% O_2 (88 percent removal) if a catalyst is used. Reductions on oil is also expected to be 88 percent (2.4 ppmvd @ 15% O_2). The estimated CO emissions for the control technology are listed in Table 5-1.

5.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenario's evaluated.

5.3.1 Economic Impacts

The use of oxidation catalyst has a significant negative economic impact to the Project. Analysis of the economic impacts is provided below. The CO BACT costs presented in this analysis are based on operating the General Electric 7FA unit at full load for 4,000 hour per year on natural gas and 800 hours per year on No. 2 fuel oil.

5.3.1.1 Capital costs.

Tables 5-2 presents the capital costs for installing an oxidation catalyst system on a General Electric 7FA. The capital costs for the systems includes the oxidation catalytic reactor and balance of plant equipment, and were based on budgetary quotations from equipment manufacturers and other engineering estimates.

5.3.1.2 Operating costs.

Table 5-3 presents the annual operating costs and emission rates using an oxidation catalyst to achieve 88 percent reduction of CO on a General Electric 7FA. CO outlet emissions would be reduced to a maximum of 1.8 ppmvd at 15 percent O_2 during natural gas firing and 2.4 ppmvd during gas firing and fuel oil firing, respectively. Annual operating costs for the systems include catalyst replacement, operating personnel, maintenance costs, and lost power generation. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours) for an oxidation catalyst. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

Total 1999 annual cost for the oxidation catalyst system is calculated as the sum of the 1999 annual operating costs plus capital recovery. The total annual operating cost for an oxidation catalyst is estimated to be $509,000. This results in an incremental CO removal cost of $4,740.

Table 5-1
Estimated CO Emissions From
Alternate Control Technologies Per GE 7FA Unit

Fuel	Control Technologies	
	Dry Low NO_x Combustors	Oxidation Catalyst 88% Reduction
Natural Gas		
Ppmvd	15	1.8
Tons per year[a]	96	11.5
Fuel Oil		
Ppmvd	20	2.4
Tons per year[b]	26	3.1
BACT Basis (Annual)[c]		
Tons per year	122	14.6

Notes:

[a] Annual emissions based on 4,000 hours of operation per year at full load rating with an ambient temperature of 59 degree F.

[b] Annual emissions are based on 800 hours of operation per year at full load rating with an ambient temperature of 59 degree F.

[c] Annual emissions are based on firing natural gas for 4,000 hours and No. 2 fuel oil for 800 hours per year at full load rating with an ambient temperature of 59 degree F.

Table 5-2
CO Reduction System Capital Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Catalysts	712,000	NA	Scaled from previous vendors quotes
Catalyst Reactor	245,000	NA	Calculated based on catalyst size
Dilution Air System	282,000	NA	Estimated for entire fan system
Control/Instrumentation	40,000	NA	Estimated
Balance of Plant	192,000	NA	For: 15% For Foundations & Supports, Erection, Electrical Installation, Painting, Insulation, Vendor Engineering.
Total Direct Capital Cost	1,471,000	Base	
Indirect Capital Costs			
Contingency	294,000	NA	20% of Direct Capital Cost
Engineering and Supervision	74,000	NA	5% of Direct Capital Cost
Construction & Field Expense	29,000	NA	2% of Direct Capital Cost
Construction Fee	15,000	NA	1% of Direct Capital Cost
Start-up Assistance	15,000	NA	1% of Direct Capital Cost
Performance Test	7,000	NA	0.5% of Direct Capital Cost
Total Indirect Capital Costs	434,000	Base	
Total Installed Cost	**1,905,000**	Base	

Table 5-3
CO Reduction System Annual Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Table 5-1
Catalyst Replacement	143,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	0	NA	See text for background information on this item
Power Consumption	29,000	NA	Includes back pressure on combustion turbine and dilution air fan energy consumption
Lost Power Generation	34,000	NA	
Total Direct Annual Cost	206,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	0	NA	60% of Operating and Maintenance Labor
Administrative Charges	38,000	NA	2% of Total Installed Cost
Property Taxes	52,000	NA	2.75% of Total Installed Cost
Insurance	19,000	NA	1% of Total Installed Cost
Capital Recovery	194,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	303,000	NA	
Total Annual Cost	**509,000**	NA	
Annual Emissions, tpy	14.6	122.0	Emissions taken from Table 5-1
Emissions Reduction, tpy	107.4	NA	Emissions calculated from Table 5-1
Total Cost Effectiveness, $/ton	4,740	NA	Total Annual Cost/Emissions Reduction

5.3.1.3 Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the back pressure on the combustion turbine. The additional back pressure of 1.5 inches, water gauge, will reduce the CT output by approximately 0.19 percent. The cost of lost power revenue due to the back pressure is included in the economic analysis.

5.3.1.4 Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions from sources firing fuel oil is that a significant percentage of the SO_2 in the flue gas will oxidize to SO_3. The higher the operating temperature the higher the SO_2 to SO_3 oxidation potential. It is estimated that between 75 and 90 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the CO oxidation catalyst being installed after the CT outlet with high temperatures. The SO3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. This is a substantial concern, especially since the unit will fire oil as alternate fuel, since increased H_2SO_4 emissions would increase PM_{10} emissions from the Project. This particulate matter will predominately consist of matter less than 10 microns in diameter (PM_{10}).

5.4 Conclusions

Installation of an oxidation catalyst system designed to reduce CO emissions by 88 percent would add approximately $509,000 to the annual operating capital cost of a GE 7FA. The resultant cost effectiveness on a per ton of CO removed basis is $4,740/ton. This is an excessivley high cost for this non-criteria pollutant. CO catalysts have not typically been applied to similar applications under BACT consideration. The emissions emitted from the CT of 15.0 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing represent emission levels lower than other recent projects that the State has permitted. Therefore, based on economic, environmental (especially with regard to PM_{10} emissions), and energy impacts, the proposed CO BACT for the control of CO emissions from each CT is good combustion practices using advanced combustion controls design. Emissions for the GE 7FA will be limited to 15.0 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

6.0 PM/PM_{10} Emissions Control

The emissions of particulate matter from the Project will be controlled by ensuring as complete combustion of the fuel as possible and by minimizing SO_2 to SO_3 oxidation. The NSPS for combustion turbines do not establish an emission limit for particulate. Natural gas contains only trace quantities of non-combustible material.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations as recently referenced by the State of Florida, such as the FPL Fort Myers (Florida), Santa Rosa (Florida), and the City of Tallahasse (Florida) projects, the use of combustion controls is considered BACT for particulate matter and is proposed for this project.. Particulate emissions (front half catch only) will be limited to 0.0055 lb/mmbtu (9 lb/hr at full load) while firing natural gas and 0.0093 lb/mmbtu (17 lb/hr at full load) while firing oil.

7.0 SO2 BACT Analysis

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. Fuel oil will be limited to less than 0.5 percent sulfur. The selection of these fuels provide inherently low SO_2 emissions. No supplemental SO_2 emission controls have been imposed on natural gas fired combustion turbines by regulatory agencies. Other recent Florida projects hav identified the use of natural gas and low sulfur oil as BACT. Since the project will be using typical natural gas as the fuel and low sulfur oil as a limited alternative fuel, the use of these fuels are considered BACT.

8.0 Summary

The following is a summary of BACT for the combustion turbines and the associated emission rates.

- Nitrogen oxides (NO_x) emissions -- Dry low NO_x burners during natural gas and fuel oil firing to achieve an emission limit of 12 ppmvd and 42 ppmvd respectively at 15 percent O_2

- Carbon monoxide (CO) emissions -- Good combustion controls to achieve a CO emission limit of 15 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

- Particulate emissions--Good combustion controls.

- Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) —Good combustion controls using natural gas and fuel oil with less than 0.5 percent sulfur.

Appendix A
BACT Clearinghouse Summary

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	CO	0.0055	LB/MMBTU	CATALYTIC OXIDATION	80	BACT-PSD
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	CO	0.015	G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	MMBTU/HR 1190 (EACH)	CO	0.026	LB/MMBTU	TURBINE DESIGN		BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	MMBTU/HR 553 EACH	CO	0.06	LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	CO	0.072	LB/MMBTU GAS (100%)	COMBUSTION CONTROL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	MMBTU/HR 206 (EACH)	CO	0.073	LB/MMBTU GAS, 100%	COMBUSTION CONTROLS		BACT-OTHER
ALGONQUIN GAS TRANSMISSION CO.	RI	1126-1127	7/31/91	TURBINE, GAS, 2	49 MMBTU/H	CO	0.114	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	DUCT BURNER, GAS	150 MMBTU/H	CO	0.2	LB/MMBTU	NOT REQUIRED		BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	503-3028-X003	8/5/93	TURBINE, NATURAL GAS	12600 BHP	CO	0.42	GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CONTROLS		BACT-PSD
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	CO	1.3	LBS/HR	GOOD COMBUSTION		BACT
NEWARK BAY COGENERATION PARTNERSHIP, L P	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	MMBTU/HR 617 (EACH)	CO	1.8	PPMDV	OXIDATION CATALYST		OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	CO	1.9	LBS/HR	GOOD COMBUSTION		BACT
TEMPLE UNIVERSITY	PA	92310	10/2/92	ELECTRIC GENERATOR (NATURAL GAS)	1.6 MW	CO	1.92	GRAMS/BHP-HR	LEAN BURN GAS ENGINE		BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	MMBTU/H 640 (EACH)	CO	2.6	PPMDV	OXIDATION CATALYST		OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	MMBTU/HR 1123 (EACH)	CO	3	PPM	OXIDATION CATALYST		BACT-OTHER
BLUE MOUNTAIN POWER, LP	PA	09-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	CO	3.1	PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRING NO. 2 OIL. AT 75% NG LIMIT SET TO 22.1 PPM	80	OTHER
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	MMBTU/HR 29 PER BURNER	CO	4	LB/HR			OTHER
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	2-6101-00185/00002-9	6/6/95	TURBINE, NATURAL GAS FIRED	240 MW	CO	4	PPM @ 15% O2			LAER
SUMAS ENERGY INC.	WA		6/25/91	TURBINE, NATURAL GAS	88 MW	CO	6	PPM @ 15% O2	CO CATALYST	80	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	CO	7.74	PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	80	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS-FIRED	47.64 MMBTU/H	CO	7.74	PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	80	BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00926/00001-9	9/1/92	TURBINE, COMBUSTION GAS (150 MW)	MMBTU/HR 1146 (GAS)*	CO	8.5	PPM	COMBUSTION CONTROL		BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	MMBTU/H, NAT 1032 GAS	CO	9	PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	CO	10	PPMVD	COMPLETE COMBUSTION		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	MMBTU/HR 1173 (EACH)	CO	10	PPM	COMBUSTION CONTROLS		BACT-OTHER
TIGER BAY LP	FL	PSD-FL-190	5/17/93	DUCT BURNER, GAS	100 MMBTU/H	CO	10	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
UNOCAL	CA	A/N 168294 AND 168295	7/18/89	TURBINE, GAS (SEE NOTES)		CO	10	PPM @ 15% O2	OXIDATION CATALYST	75	BACT-OTHER
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/5/91	TURBINE, GAS, 4 EACH	35 MW	CO	10	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	CO	10.5	PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	CO	10.5	PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	MMBTU/H 1360 EACH	CO	11	PPM @ 15% O2, GAS			BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040-00007-9	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	MMBTU/HR 2133 (EACH)	CO	13	PPM	COMBUSTION CONTROLS		BACT-OTHER
MARATHON OIL CO. - INDIAN BASIN N.G PLAN	NM	PSD-NM-295-M-2	1/11/95	TURBINES, NATURAL GAS (2)	5500 HP	CO	13.2	LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.	66	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	CO	15	PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	25-0031	5/31/94	TURBINES, NATURAL GAS (2)	1720 MMBTU	CO	15	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
HERMISTON GENERATING CO.	OR	30-0113	4/1/94	TURBINES, NATURAL GAS (2)	1696 MMBTU	CO	15	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	CO	20	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	AC44-245399 / PSD-FL-210	9/28/95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	CO	20	PPM @ 15% O2 FULL LD	GOOD COMBUSTION		BACT-PSD
KALAMAZOO POWER LIMITED	MI	1234-90	12/3/91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805 9 MMBTU/H	CO	20	PPMV	DRY LOW NOX TURBINES		BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	MMBTU/H 385 EACH TURBINE	CO	22.4	PPM @ 15% O2			BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	CO	23	LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
PANDA-KATHLEEN, L.P.	FL	AC53-251898/PSD-FL-216	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	CO	25	PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE CT IS SELECTED, THE ABB CT WAS LESS THAN SIGNIFICANT EMIS. INCR FOR CO		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	CO	25	PPM	COMBUSTION CONTROL		BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	CO	25	PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	CO	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	CO	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	CO	25	PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	PSD-LA-560 (M-1)	3/2/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	CO	25.8	LB/HR	PROPER OPERATION		BACT-PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	CO	27	LBS/HR	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPER AIR-FUEL RATIO.		BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-859-M-4		TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	CO	27.6	PPM @ 15% O2			BACT-PSD
MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	CO	28	PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	CO	30	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	CO	30	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	CO	30	PPMVD	GOOD COMBUSTION		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	CO	33	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	CO	39.98	LBS/HR	CATALYTIC CONVERTER		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	CO	39.98	LBS/HR	CATALYTIC CONVERTER		BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR-89-COM-032	11/30/89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	CO	40	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-OTHER
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367 MMBTU/H	CO	40	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	TURBINE, GAS, 2 EACH	42 MW	CO	42	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	TURBINE, GAS	1614.8 MMBTU/H	CO	49	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	CO	50	PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340M2	10/29/93	TURBINE, GAS-FIRED	11257 HP	CO	50	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	869 MMBTU/H	CO	54	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	CO	59	LB/HR	COMBUSTION CONTROL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	CO	60	LB/HR	COMBUSTION CONTROL		BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	PSD-LA-569	8/5/91	TURBINE, GAS, 2	39.1 MMBTU/H	CO	60	PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS		BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	CO	60	PPM @ 15% O2	LEAN BURN		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	PSD-LA-560 (M-2)	3/7/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	CO	70	LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.		BACT-PSD
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	CO	91.18	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		OTHER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	GE LM-5000 GAS TURBINE	550 MMBTU/HR	CO	92	LB/HR TEMP > 20F	NO CONTROLS		BACT-OTHER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	CO	106.4	LB/HR TEMP > 20F	OXIDATION CATALYST	80	BACT
NORTHERN CONSOLIDATED POWER	PA	25-328-001	5/3/91	TURBINES, GAS, 2	34.6 KW EACH	CO	110	T/YR	OXIDATION CATALYST	90	OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	CO	152 5	TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR		BACT-PSD
INTERNATIONAL PAPER	LA	PSD-LA-93(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	CO	165.9	LB/HR	COMBUSTION CONTROL		BACT
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	DUCT BURNER	710 MM BTU/HR	CO	198 6	LB/HR COMMON VENT	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE		BACT-PSD
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313 MM BTU/HR	CO	198.6	LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE		BACT-PSD
CIMARRON CHEMICAL	CO	90WE438	3/25/91	TURBINE #2, GE FRAME 6	33 MW	CO	250	T/YR, LESS THAN	CO CATALYST		OTHER
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	CO	300	TPY	INTERNAL COMBUSTION CONTROLS		BACT
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	DUCT BURNER	450 MM BTU/HR	CO	600	MM BTU/HR CAP FOR 3	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	CO	972 4	TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	CO		SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	CO, GAS	33	PPMDV	COMBUSTION CONTROLS.		BACT-PSD
PORTSIDE ENERGY CORP.	IN	CP 127 5260	5/13/96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	CO, NON-POWER MODE	12	LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 PPMVD AT 15% OXYGEN		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	CO, OIL	100	PPMDV AT MIN. LOAD	COMBUSTION CONTROLS.		BACT-PSD
PORTSIDE ENERGY CORP.	IN	CP 127 5260	5/13/96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	CO, POWER MODE	40	LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 40 PPMVD AT 15% OXYGEN.		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	H2SO4	7.5	LB/H	FUEL SPEC: LOW SULFUR IN NATURAL GAS		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	H2SO4	25.1	LB/HR	FUEL SPEC: 0.2% SULFUR FUEL OIL		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	H2SO4			FUEL SPEC: LIMIT FUEL SULFUR CONTENT		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	H2SO4			FUEL SPEC: NATURAL GAS AS FUEL		BACT-PSD

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SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 (EACH) MMBTU/HR	H2SO4 MIST	0.0035	LB/MMBTU	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 (EACH) MMBTU/HR	H2SO4 MIST	0.021	LB/MMBTU OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-859-M-4		TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	NO2	9	PPM @ 15% O2	DRY LOW NOX (GENERAL ELECTRIC MODEL PG6541B)	94	BACT-PSD
ALABAMA POWER COMPANY	AL	108-0018-X001 AND -X002	12/17/97	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100 MW	NO2	15	PPM	DRY LOW NOX BURNERS		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	NO2	15	PPM @ 15% O2	DRY BURN LOW NOX BURNERS	91	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/90	TURBINE, 105 MW OIL FIRED ELECTRIC	105 MW	NO2	25	PPM @ 15% O2	DRY PREMIX BURNER		BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/90	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	NO2	25	PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION		BACT-PSD
LINDEN COGENERATION TECHNOLOGY	NJ		1/21/92	TURBINE, NATURAL GAS FIRED	50 X E12 BTU/YR	NO2	33.8	LB/HR	STEAM INJECTION AND SCR	94.5	BACT-PSD
PEPCO - STATION A	MD		5/31/90	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	NO2	42	PPM @ 15% O2	WATER INJECTION		BACT-PSD
SOUTHERN NATURAL GAS	AL	412-0013-X001 AND -X002	3/4/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	NO2	53	LB/HR			BACT-PSD
SOUTHERN NATURAL GAS	AL	206-0021-X001 AND -X002	3/2/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	NO2	53	LB/HR			BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	NO2	61.26	LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	NO2	61.26	LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	NO2	65	PPM @ 15% O2	WATER INJECTION	72	BACT-PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	NO2	74.4	LBS/HR	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCHEDULED COMBUSTION.	80	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/90	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	NO2	77	PPM @ 15% O2	DRY PREMIX AND WATER INJECTION		BACT-PSD
PEPCO - STATION A	MD		5/31/90	TURBINE, 124 MW OIL FIRED	125 MW	NO2	77	PPM @ 15% O2	WATER INJECTION		BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	NO2	88 6	TPY (EACH TURBINE)	LOW NOX COMBUSTOR		BACT-PSD
NORTHWEST PIPELINE COMPANY	WA	92-4	8/13/92	TURBINE, GAS-FIRED	12100 HP	NO2	196	PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/95)	76	BACT-PSD
PACIFIC GAS TRANSMISSION COMPANY	OR	16-0026	6/19/90	TURBINE GAS, COMPRESSOR STATION	110 MMBTU/HR	NO2	199	PPM @ 15% O2	LOW NOX BURNER DESIGN	30	NSPS
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	MD		10/1/89	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	NO2	199	LB/HR	WATER INJECTION		BACT-PSD
CITY OF ST.PAUL POWER PLANT	AK	9625-AA004	6/27/96	INTERNAL COMBUSTION	3 4 MW	NO2	427	TPY	AFTERCOOLERS		BACT-PSD
CITY OF UNALASKA	AK	9625-AA003	6/21/96	INTERNAL COMBUSTION	6.5 MW	NO2	632 6	TPY	LIMIT OF OPERATION HOURS AND AFTERCOOL		BACT-PSD

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SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	208 MMBTU/HR (EACH)	NOX	0.0181	LB/MMBTU GAS	LOW NOX BURNER AND SCR		BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	NOX	0.033	LB/MMBTU	STEAM INJECTION AND SCR	94	BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	NOX	0.033	LB/MMBTU	SCR, DRY LOW NOX BURNER	64	BACT-OTHER
NUGGET OIL CO.	CA	4131003	10/8/91	GENERATOR, STEAM, GAS FIRED	62.5 MMBTU/H	NOX	0.043	LB/MMBTU	LOW NOX BURNER AND FLUE GAS RECIRCULATION*	57	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	NJ		2/23/90	TURBINE, NATURAL GAS FIRED	1000 MMBTU/HR	NOX	0.044	LB/MMBTU	STEAM INJECTION AND SCR	93	BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	553 MMBTU/HR EACH	NOX	0.08	LB/MMBTU	SCR		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	NOX	0.091	LB/MMBTU, GAS	LOW NOX BURNER		BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	BURNER, DUCT	90 MMBTU/HR	NOX	0.1	LB/MMBTU	LOW NOX BURNER		BACT-OTHER
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	DUCT BURNER	710 MM BTU/HR	NOX	0.1	LB/MM BTU	LOW NOX BURNERS		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	DUCT BURNER, GAS	150 MMBTU/H	NOX	0.1	LB/MMBTU	NOT REQUIRED		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	DUCT BURNER, GAS	100 MMBTU/H	NOX	0.1	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-PSD
TEMPO PLASTICS	CA	S-995-5-0	12/31/96	GAS TURBINE COGENERATION UNIT		NOX	0.109	LB/MMBTU	LOW-NOX COMBUSTOR		LAER
FLORIDA GAS TRANSMISSION COMPANY	AL	503-3028-X003	8/5/93	TURBINE, NATURAL GAS	12600 BHP	NOX	0.58	GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION	71	BACT-PSD
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	NOX	1.6	G/HP-HR*	LOW NOX COMBUSTION		BACT-OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	NOX	1.7	LBS/HR	RETROFIT W/AN AIR TO FUEL RATIO CONTROL W/ NON-SELECTIVE CATALYTIC REDUCTION (NSCR)		BACT
TEMPLE UNIVERSITY	PA	92310	10/2/92	ELECTRIC GENERATOR (NATURAL GAS)	1.6 MW	NOX	2	GRAM/BHP-HR	LEAN BURN GAS ENGINE		BACT-OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	NOX	2.5	LBS/HR	RETROFIT W/AN AIR TO FUEL RATIO CONTROL W/ NON-SELECTIVE CATALYTIC REDUCTION (NSCR)		BACT
GRANITE ROAD LIMITED	CA	4216001	5/6/91	TURBINE, GAS, ELECTRIC GENERATION	460.9 MMBTU/H*	NOX	3.5	PPMVD @ 15% O2	SCR, STEAM INJECTION	97	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	2-6101-00185/00002-9	6/6/95	TURBINE, NATURAL GAS FIRED	240 MW	NOX	3.5	PPM @ 15% O2	SCR		LAER
BLUE MOUNTAIN POWER, LP	PA	09-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	NOX	4	PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING OIL. OIL FIRING LIMITS SET TO 8.4 PPM @15% O2	84	LAER
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040-00007-9	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	NOX	4.5	PPM	SCR AND DRY LOW NOX		BACT-OTHER
PORTLAND GENERAL ELECTRIC CO.	OR	25-0031	5/31/94	TURBINES, NATURAL GAS (2)	1720 MMBTU	NOX	4.5	PPM @ 15% O2	SCR	82	BACT-PSD

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HERMISTON GENERATING CO	OR	30-0113	4/1/94	TURBINES, NATURAL GAS (2)	1696 MMBTU	NOX	4.5	PPM @ 15% O2	SCR	82	BACT-PSD
GOAL LINE, LP ICEFLOE	CA	911504	11/3/92	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386 MMBTU/HR	NOX	5	PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT.	88	BACT-OTHER
SUMAS ENERGY INC.	WA		6/25/91	TURBINE, NATURAL GAS	88 MW	NOX	6	PPM @ 15% O2	SCR	90	BACT-PSD
KINGSBURG ENERGY SYSTEMS	CA	3040230101	9/28/89	TURBINE, NATURAL GAS FIRED, DUCT BURNER	34.5 MW	NOX	6	PPM @ 15% O2	SCR, STEAM INJECTION	90	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	PSD-NM-295-M-2	1/11/95	TURBINES, NATURAL GAS (2)	5500 HP	NOX	7.4	LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DRY/LOW NOX	66	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	NOX	8	PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	93	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS-FIRED	47.64 MMBTU/H	NOX	8	PPMVD @ 15% O2	HIGH TEMPERATURE SELECTIVE CATALYTIC REDUCTION	93	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	MMBTU/HR 617 (EACH)	NOX	8.3	PPMDV	SCR		BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	NOX	9	PPMVD	DRY LOW NOX BURNER WITH SCR		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	MMBTU/HR 1173 (EACH)	NOX	9	PPM GAS	STEAM INJECTION AND SCR		BACT-OTHER
CIMARRON CHEMICAL	CO	90WE438	3/25/91	TURBINE #2, GE FRAME 6	33 MW	NOX	9	PPM @ 15% O2	SCR		OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	NOX	9	PPM	DRY LOW NOX OR SCR		BACT-OTHER
SEMINOLE FERTILIZER CORPORATION	FL	PSD-FL-157	3/17/91	TURBINE, GAS	26 MW	NOX	9	PPM @ 15% O2	SCR		BACT-PSD
UNOCAL	CA	A/N 168294 AND 168295	7/18/89	TURBINE, GAS (SEE NOTES)		NOX	9	PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION (SCR), WATER INJECTN	80	BACT-OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	MMBTU/H 1360 EACH	NOX	9	PPM @ 15% O2, GAS	SCR		BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	PSD-LA-560 (M-1)	3/2/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	NOX	9	PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL		LAER
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	PSD-LA-560 (M-2)	3/7/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	NOX	9	PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRUCTION		BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	MMBTU/HR 1123 (EACH)	NOX	9	PPM	SCR		BACT-OTHER
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	NOX	12	PPMVD @15 % O2	DRY LOW NOX COMBUSTOR		BACT-PSD
PANDA-KATHLEEN, L.P.	FL	AC53-251898/PSD-FL-216	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	NOX	15	PPM @ 15% O2	DRY LOW NOX BURNER		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	NOX	15	PPM (SEE FAC. NOTES)	DRY LOW NOX COMBUSTION		BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	NOX	15	PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	TURBINE, GAS	1614.8 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
KALAMAZOO POWER LIMITED	MI	1234-90	12/3/91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805.9 MMBTU/H	NOX	15	PPMV	DRY LOW NOX TURBINES		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	869 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD

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KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	NOX	15	PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR		BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	NOX	21	LB/HR	SCR WITH LOW NOX COMBUSTORS	47	BACT-OTHER
PHOENIX POWER PARTNERS	CO	92WE1357	5/11/93	TURBINE (NATURAL GAS)	311 MMBTU/HR	NOX	22	PPM @ 15% O2	DRY LOW NOX COMBUSTION		BACT-OTHER
MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	NOX	25	PPMVD@ 15% O2 (GAS)	FUEL OIL SULFUR CONTENT <=0.05% BY WEIGHT DRY LOW NOX COMBUSTOR DESIGN FIRING GAS AND DRY LOW NOX COMBUSTOR WITH WATER INJECTION FIRING OIL		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	NOX	25	PPM GAS	STEAM INJECTION		BACT-OTHER
NORTHERN CALIFORNIA POWER AGENCY	CA	N-583-1-1	10/2/97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	NOX	25	PPMVD @ 15% O2	DRY LOW NOX BURNERS		LAER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	GE LM-5000 GAS TURBINE	550 MMBTU/HR	NOX	25	PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	80	BACT
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313 MM BTU/HR	NOX	25	PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	NOX	25	PPMV-CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION		BACT-PSD
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	NOX	25	PPMV@15%O2	SOLONOX BURNER: LOW NOX BURNER		BACT-OTHER
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	NOX	25	PPM @ 15% O2	DRY LOW NOX BURNER	74	BACT-PSD
CIMARRON CHEMICAL	CO	90WE438	3/25/91	TURBINE #1, GE FRAME 6	33 MW	NOX	25	PPM @ 15% O2	WATER INJECTION		OTHER
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR-89-COM-032	11/30/89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	NOX	25	PPM @ 15% O2	WATER INJECTION		BACT-OTHER
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	4911-076-11348	5/13/94	TURBINE, COMBUSTION, NATURAL GAS	80 MW	NOX	25	PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS		BACT-PSD
FLORIDA GAS TRANSMISSION	FL	FL-PSD-202	9/27/93	TURBINE, GAS	131.59 MMBTU/H	NOX	25	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	NOX	25	PPM @ 15% O2	MAXIMUM WATER INJECTION		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	NOX	25	PPM @ 15% O2	DRY LOW NOX TECH.		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	NOX	25	PPM @ 15% O2	WET INJECTION		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	TURBINE, GAS, 2 EACH	42 MW	NOX	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	NOX	25	PPM @ 15% O2	LOW NOX COMBUSTORS		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC	BASIS
INTERNATIONAL PAPER	LA	PSD-LA-93(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	NOX	25	PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL		BACT
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	NOX	25	PPM @ 15% O2	MAX WATER INJECTION		BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	25-328-001	5/3/91	TURBINES, GAS, 2	34.6 KW EACH	NOX	25	PPM @ 15% O2	STEAM INJECTION/+SCR IN 1997	85	OTHER
SOUTHERN CALIFORNIA GAS COMPANY	CA	S-1792-5-3	5/14/97	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50.1 MMBTU/HR	NOX	25	PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR		LAER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	NOX	26	PPM, 69 LB/HR	NO CONTROLS FOR NOX ON STACK *SEE TURBINE NOX DATA		BACT-OTHER
ENRON LOUISIANA ENERGY COMPANY	LA	PSD-LA-569	8/5/91	TURBINE, GAS, 2	39.1 MMBTU/H	NOX	40	PPM @ 15% O2	H2O INJECT 0.67 LB/LB	71	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	NOX	42	PPM @ 15% O2	LOW NOX COMBUSTORS		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	NOX	42	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/5/91	TURBINE, GAS, 4 EACH	35 MW	NOX	42	PPM @ 15% O2	WET INJECTION	70	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	42	PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	42	PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340M2	10/29/93	TURBINE, GAS-FIRED	11257 HP	NOX	42	PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY	66	BACT-PSD
PACIFIC GAS TRANSMITION	OR	16-0026	11/3/89	TURBINE, NAT. GAS	14600 HP	NOX	42	PPM @ 15% O2	LOW NOX BURNERS	75	BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	NOX	42	PPM @ 15% O2	DRY LOW NOX COMBUSTOR	80	BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	MMBTU/H 385 EACH TURBINE	NOX	42	PPM @ 15% O2	WATER INJECTION	66	BACT-PSD
SOUTHERN NATURAL GAS COMPANY-SELMA COMPRESSOR STAT	AL	104-0021-X001 AND -X002	12/4/96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE		NOX	53	LB/HR			BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	PA	66-0001	5/31/95	TURBINE, NATURAL GAS	580 MMBTU/HR	NOX	55	PPM @ 15% O2	STEAM INJECTION	75	RACT
KEY WEST CITY ELECTRIC SYSTEM	FL	AC44-245399 / PSD-FL-210	9/28/95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	NOX	75	PPM @ 15% O2	WATER INJECTION		BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	84.9	PPM @ 15% O2	LEAN BURN		NSPS
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	85.1	PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		NSPS
ALGONQUIN GAS TRANSMISSION CO.	RI	1126-1127	7/31/91	TURBINE, GAS, 2	49 MMBTU/H	NOX	100	PPM @ 15% O2	LOW NOX COMBUSTION		BACT-OTHER
SOUTHERN NATURAL GAS COMPANY	MS	1300-00031	12/17/96	TURBINE, NATURAL GAS-FIRED	9160 HORSEPOWER	NOX	110	PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION		BACT-PSD

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DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	NOX	119	LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	NOX	200	TPY	INTERNAL COMBUSTION CONTROLS		BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	NOX	225	PPM @ 15% O2	LEAN BURN		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	NOX	287	LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	NOX	308	LBS/HR	WATER INJECTION		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	NOX		SEE FACILITY NOTES	DRY LOW NOX COMBUSTION		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	DUCT BURNER	450 MM BTU/HR	NOX		USE LOW NOX BURNERS	LOW NOX BURNERS		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	NOX		SEE NOTES	MAX WATER INJECTION		BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00926/00001-9	9/1/92	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	NOX (FROM GAS)	9	PPM	DRY LOW NOX		BACT-OTHER
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	NOX, GAS	60	LB/HR	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	72	BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	PM	0.0023	LB/MMBTU	TURBINE DESIGN		BACT-OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	PM	0.005	LB/MMBTU, GAS			BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	DUCT BURNER, GAS	150 MMBTU/H	PM	0.006	LB/MMBTU	FUEL SPEC: LIMITED TO NATURAL GAS		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	PM	0.006	LB/MMBTU	COMBUSTION CONTROL		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	PM	0.006	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	PM	0.0064	LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	TURBINE, GAS, 2 EACH	42 MW	PM	0.0065	LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	DUCT BURNER, GAS	100 MMBTU/H	PM	0.01	LM/MMBTU	GOOD COMBUSTION PRACTICES		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	PM	0.012	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	PM	0.0136	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-PSD
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	PM	0.035	LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS		OTHER
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	29 MMBTU/HR PER BURNER	PM	0.4	LB/HR			OTHER

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MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	PM	2.5	LBS/HR (GAS)	PRIMARY FUEL IS NATURAL GAS WITH BACKUP FUEL AS DISTILLATE OIL. EFFICIENT OPERATION OF THE COM- BUSTION TURBINE		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	PM	5	LB/H	GOOD COMBUSTION		BACT-PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	PM	5.3	LBS/HR	HIGH COMBUSTION EFFICIENCY USE OF NO.2 LOW SULFUR FUEL OIL (LESS THAN 0.05% BY WT.)		BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	PM	7	LB/HR AT 20 F	FUEL SPEC: LOW SULFUR FUELS		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	869 MMBTU/H	PM	7	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	PM	8	LB/HR			BACT-OTHER
TIGER BAY LP	FL	PSD-FL-190	5/17/93	TURBINE, GAS	1614.8 MMBTU/H	PM	9	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367 MMBTU/H	PM	9	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	PM	9	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	PM	9.9	T/YR			OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	PM	12.4	T/YR			OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	PM	15.4	LB/H	COMBUSTION CONTROL		BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	PM	18	LB/HR	CLEAN FUEL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	PM	18	LB/H	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	PM	19	LB/H	COMBUSTION CONTROL		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	PM	25.8	LB/H	FUEL SPEC: NATURAL GAS FIRED		OTHER
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	PM	45	LBS/HR	FUEL SPEC: LOW ASH CONTENT FUELS		BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	PM,PM10	0.033	LB/MMBTU, 25 LB/HR	NO CONTROLS		BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	553 MMBTU/HR EACH	PM/PM10	0.003	LB/MMBTU	COMBUSTION CONTROLS		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	PM/PM10	0.004	LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	PM/PM10	0.004	LB/MMBTU GAS (BASE)	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	PM/PM10	0.0062	LB/MMBTU	COMBUSTION CONTROLS		BACT-OTHER

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KAMINE/BESICORP CORNING L P	NY	8-4638-00022/01-0	11/5/92	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	PM/PM10	0.008	LB/MMBTU	COMBUSTION CONTROL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	PM/PM10	0.014	LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC. LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 MMBTU/HR (EACH)	PM/PM10	0.014	LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	BURNER, DUCT	90 MMBTU/HR	PM/PM10	0.05	LB/MMBTU	COMBUSTION CONTROL		BACT-OTHER
PORTSIDE ENERGY CORP.	IN	CP 127 5260	5/13/96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	PM/PM10	5	LBS/HR			BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L P	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	PM10	0.006	LB/MMBTU	TURBINE DESIGN		BACT-PSD
TEMPO PLASTICS	CA	S-995-5-0	12/31/96	GAS TURBINE COGENERATION UNIT		PM10	0.012	LB/MMBTU	LUBE OIL VENT COALESCER. OPACITY LIMIT APPLIES TO LUBE OIL VENTS.		LAER
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	PM10	3	LBS/HR	FUEL SPEC: BURN NATURAL GAS		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	PM10	3	LBS/HR	FUEL SPEC. BURN NATURAL GAS		BACT-PSD
BMW MANUFACTURING CORPORATION	SC	2060-0230-CA THROUGH CR	1/7/94	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54 5 MM BTU/HR TURBINES	PM10	3.79	TPY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK		BACT-PSD
NORTHERN CALIFORNIA POWER AGENCY	CA	N-583-1-1	10/2/97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	PM10	4.3	LB/DAY	NATURAL GAS, AIR INTAKE COOLER, VENTING THE LUBE OIL VENT INTO THE EXHAUST STREAM OF THE TURBINE FOR OXIDATION OF THE SMOKE		LAER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	PM10	5	LB/HR	COMBUSTION CONTROL		BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	PM10	9.9	T/YR			OTHER
SOUTHERN NATURAL GAS	AL	412-0013-X001 AND -X002	3/4/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	PM10	10.95	TPY	FUEL SPEC: NATURAL GAS		BACT-PSD
SOUTHERN NATURAL GAS	AL	206-0021-X001 AND -X002	3/2/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	PM10	10.95	TPY	FUEL SPEC: NATURAL GAS		BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	PM10	12.4	T/YR			OTHER
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	DUCT BURNER	710 MM BTU/HR	PM10	18.3	LB/HRCOMMON VENT	NO ADD-ON CONTROL CLEAN FUEL		BACT-PSD
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313 MM BTU/HR	PM10	18.3	LB/HR	NO CONTROL CLEAN FUEL		BACT-PSD
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	PM10	20.2	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		BACT-OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	PM10	30.6	TPY (EACH TURBINE)	PRECISION CONTROL FOR THE COMBUSTOR		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	PM10	52	TPY	INTERNAL COMBUSTION CONTROLS		BACT

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GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	PM10	92	TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	DUCT BURNER	450 MM BTU/HR	PM10	600	MM BTU/HR CAP FOR 3	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	PM10		SEE P2	GOOD COMBUSTION PRACTICES		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	PM10					BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-859-M-4		TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	PM10		SEE P2 DESC.	COMBUSTION AIR FILTERS, GOOD COMBUSTION PRACTICE AND MAINTENANCE		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	PM10, COOLING TOWER	0.0015	% OF FLOW	TWO STAGE MIST ELIMINATOR TO RESTRICT DRIFT.		BACT-OTHER
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	PM10, GAS	12	LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES. FUEL SPEC: USE OF NG/LPG.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	PM10, OIL	59	LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES. FUEL SPEC: USE OF NG/LPG.		BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	SO2	0.0026	LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS		BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	SO2	0.0069	LB/MMBTU	FUEL SPEC: NAT GAS/LOW SULFUR NO 2 OIL		BACT-OTHER
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	29 MMBTU/HR PER BURNER	SO2	0.03	LB/HR			OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	SO2	0.0834	LB/H	FUEL SPEC: COAL DERIVED GAS		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 MMBTU/HR (EACH)	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00926/00001-9	9/1/92	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	SO2	0.5	% S MAX	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	SO2	0.7	LB/HR	COMBUSTION CONTROL		BACT-PSD

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PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	SO2	0.95	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		OTHER
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	SO2	0.99	LB/H	FUEL SPEC: LOW SULFUR IN NATURAL GAS		BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	SO2	2.1	LB/HR	FUEL SPEC: USE OF LOW-SULFUR OIL AS STANDBY FUEL		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	SO2	2.1	LBS/HR	FUEL SPEC: USE OF LOW SULFUR OIL AS THE STAND-BY FUEL		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	SO2	2.8	TPY	INTERNAL COMBUSTION CONTROLS		BACT
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	SO2	2.8	LBS/HR	USE OF SWEET NATURAL GAS AND NO.2 DIESEL FUEL WITH LESS THAN 0.05% BY WT. OF SULFUR		BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	SO2	3.2	T/YR			OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	SO2	3.2	T/YR			OTHER
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	SO2	11.3	LB/HR	FUEL SPEC: 0.1 % SULFUR IN FUEL		BACT-OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	SO2	27.1	TPY (EACH TURBINE)	FUEL SPEC: S IN #2 DISTILLATE LIMITED TO 0.05%		BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	SO2	29	LB/HR AT 20 F (GAS)	FUEL SPEC: LOW SULFUR OIL BACKUP FUEL AND NAT GAS PRIMARY 0.05% S		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	SO2	40	LB/H	FUEL SPEC: LOW SULFUR IN NATURAL GAS		BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	4911-076-11348	5/13/94	TURBINE, COMBUSTION, NATURAL GAS	80 MW	SO2	56	PPM	FUEL SPEC: LOW SULFUR FUEL (.3% AVG) FUEL 0.1		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	SO2	87	LB/HR	FUEL SPEC. LOW SULFUR OIL (0.05%)	75	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	SO2	91.5	LB/H	FUEL SPEC: NATURAL GAS AS FUEL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	SO2	240.7	LB/HR	FUEL SPEC. 0.2% SULFUR FUEL OIL		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	SO2	630	LBS/HR	FUEL SPEC: LOW SULFUR CONTENT FUELS		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SO2		SEE P2	SWEET PIPELINE NATURAL GAS		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SO2		SEE FACILITY NOTES	SWEET PIPELINE NATURAL GAS		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	SO2			FUEL SPEC: LIMIT FUEL SULFUR CONTENT		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	SO2			FUEL SPEC: NATURAL GAS AS FUEL		BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040-00007-9	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	SO2			FUEL SPEC: USE OF NATURAL GAS		BACT-OTHER

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ECOELECTRICA, L P	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	SO2, GAS		NEGLIGIBLE	FUEL SPEC: LNG/LPG AS PRIMARY FUEL, 0.04% SULFUR NO. 2 OIL AS BACKUP FUEL.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	SO2, OIL	70.5	LB/HR	FUEL SPEC: LNG/LPG AS PRIMARY FUEL, 0.04% SULFUR NO. 2 OIL AS BACKUP FUEL		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	SOX	1.5	LB/H			OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	TSP	0.006	LB/MMBTU	TURBINE DESIGN		OTHER
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	VE	10	% OPACITY	COMPLETE COMBUSTION		BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	VE	10	% OPACITY	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	VE	10	% OPACITY	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	VE	10	% OPACITY	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	VE	20	% OPACITY	GOOD COMBUSTION PRACTICES		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	VE	20	% OPACITY	COMBUSTION CONTROL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	VE	20	% OPACITY	COMBUSTION CONTROL		BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	553 MMBTU/HR EACH	VOC	0.0011	LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	VOC	0.003	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	VOC	0.0042	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	VOC	0.0045	LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
LAKEWOOD COGENERATION, L P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	VOC	0.0046	LB/MMBTU	TURBINE DESIGN		OTHER
ALGONQUIN GAS TRANSMISSION CO.	RI	1126-1127	7/31/91	TURBINE, GAS, 2	49 MMBTU/H	VOC	0.016	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	VOC	0.1	G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	VOC	0.4	LBS/HR	GOOD COMBUSTION		BACT
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	VOC	0.6	LBS/HR	GOOD COMBUSTION		BACT
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	VOC	1	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD

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NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	MMBTU/HR 29 PER BURNER	VOC	1.6	LB/HR			OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	VOC	1.6	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	VOC	2	LB/HR	COMBUSTION CONTROL		BACT-PSD
INTERNATIONAL PAPER	LA	PSD-LA-93(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	MM BTU/HR 338 TURBINE	VOC	3.8	LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION		BACT
BLUE MOUNTAIN POWER, LP	PA	09-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	VOC	4	PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL EMISSION LIMIT = 4.4 PPMVD @ 15% O2. @ 75% LOAD ALTERNATE GAS LIMIT 7.6 PPM	12	LAER
NEWARK BAY COGENERATION PARTNERSHIP, L P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	MMBTU/HR 617 (EACH)	VOC	4	PPMDV	TURBINE DESIGN		BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	VOC	4.4	LB/HR	GOOD COMBUSTION PRACTICES		BACT-OTHER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	VOC	5	LB/HR	COMBUSTION CONTROL		BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	MMBTU/H 1360 EACH	VOC	5	PPM @ 15% O2			BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	VOC	5.2	PPM, 2.8 LB/HR	NO CONTROLS		BACT-OTHER
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	VOC	6	PPMVD	COMPLETE COMBUSTION		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	VOC	6	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/5/91	TURBINE, GAS, 4 EACH	35 MW	VOC	7	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	VOC	7	PPMVW	GOOD COMBUSTION PRACTICES		BACT-PSD
NORTHERN CALIFORNIA POWER AGENCY	CA	N-583-1-1	10/2/97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	VOC	8	LB/HR	NATURAL GAS AS PRIMARY FUEL		LAER
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	VOC	9	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	VOC	10	LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	VOC	10	PPMVD	GOOD COMBUSTION		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	VOC	16.7	LB/H			OTHER
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	VOC	24.09	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		OTHER
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	VOC	25	PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340M2	10/29/93	TURBINE, GAS-FIRED	11257 HP	VOC	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD

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BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	VOC	26.7	T/YR			OTHER
TEMPLE UNIVERSITY	PA	92310	10/2/92	ELECTRIC GENERATOR (NATURAL GAS)	1.6 MW	VOC	31	LBS/HR	LEAN BURN GAS ENGINE		BACT-OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	VOC	35.2	T/YR			OTHER
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	VOC	38	TPY	INTERNAL COMBUSTION CONTROLS		BACT
BMW MANUFACTURING CORPORATION	SC	2060-0230-CA THROUGH CR	1/7/94	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	VOC	77.86	LBS/DAY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK		LAER
NORTHERN CONSOLIDATED POWER	PA	25-328-001	5/3/91	TURBINES, GAS, 2	34.6 KW EACH	VOC	105	PPM @ 15% O2	OXIDATION CATALYST	50	OTHER
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	VOC		SEE P2	GOOD COMBUSTION PRACTICES		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	VOC					BACT-PSD
TOYOTA MOTOR CORPORATION SVCS OF N A.	IN	CP-051-5391-00037	8/9/96	GASOLINE STORAGE TANKS (4)	19015 GALLONS	VOC		SEE CONTROL/P2	STAGE I VAPOR RECOVERY SYSTEM & SUBMERGE FILL PIPES		BACT-PSD
TOYOTA MOTOR CORPORATION SVCS OF N A.	IN	CP-051-5391-00037	8/9/96	GASOLINE TANK FILLING (ASSEMBLY FINAL LINE)		VOC		SEE P2	STAGE II VAPOR CONTROL		BACT-PSD
ECOELECTRICA, L P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	VOC, GAS	5	PPMDV	COMBUSTION CONTROLS.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	VOC, OIL	8	PPMDV	COMBUSTION CONTROL.		BACT-PSD

Attachment 5

(Dispersion Modeling Protocol)

BLACK & VEATCH LLP

MEMORANDUM

Jacksonville Electric Authority
Brandy Branch Simple Cycle CT Project
Air Dispersion Modeling Protocol

B&V Project 60903
B&V File 15.0100
November 20, 1998

To: Cleve Holladay

From: Kyle J Lucas

As discussed at the meeting held with FDEP on November 4, 1998, B&V is submitting the summarized modeling protocol regarding the Air Quality Impact Analysis (AQIA) air dispersion modeling methodology for the JEA Brandy Branch simple cycle combustion turbine project. Please review and provided any comments or FDEP acceptance of this protocol the by November 25, 1998. If you have any questions please contact me at 913-458-9062.

- Air Dispersion Model: ISCST3 (Use the latest version).

- Model Options: EPA Default and flat terrain.

- GEP & Downwash:

EPA's BPIP program will be used to determine GEP stack height and direction specific building downwash for the simple cycle stack.

- Receptor Grids:

A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 to 5 km, 500 m spacing from 5 to 7 km, and 1,000 m spacing from7 to 10 km. Fenceline receptors at 50 m spacing and 100 m fine grid at maximum impact locations.

- Dispersion Coefficients:

Rural: based on visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.

- Meteorological Data:

Refined level modeling sequential meteorological data will consist of surface data from Jacksonville, Florida and upper air data from Waycross, Georgia for the years 1984 to 1988.

- Source Modeling Parameters:

Worst-case hourly emissions rates and operating parameters will be used for short-term modeling impacts. Emission rates and operating parameters for annual modeling impacts will be based on annual average data.

- Modeled impacts:

It is anticipated that the maximum model predicted impacts will be less than the PSD significant impact levels (SILs) for all applicable pollutants and averaging times. If this is not the case, additional agency consultation regarding increment and ambient air quality impact analyses will be initiated.

- Class I Analysis:

A regional haze visibility study and Class I SIL analysis will be performed for Class I areas within 150 km from the proposed Facility location. These areas will consists of Okefenokee and Wolf Island Wilderness Areas.

- Toxics: A toxic modeling analysis is not required.

Attachment 6
(VISCREEN Model Output)

Visual Effects Screening Analysis for
Source: Brandy Branch
Class I Area: Okefenokee Wilderness Ar

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	51.80	LB /HR
NOx (as NO2)	1025.70	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	34.00 km
Min. Source-Class I Distance:	34.00 km
Max. Source-Class I Distance:	80.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	4
Wind Speed:	3.53 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	140.	45.4	29.	2.08	1.321	.05	-.004
SKY	140.	140.	45.4	29.	2.00	.548	.05	-.007
TERRAIN	10.	84.	34.0	84.	2.87	.437	.06	.003
TERRAIN	140.	84.	34.0	84.	2.00	.181	.06	.002

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	15.	19.9	154.	2.00	1.931	.05	-.006
SKY	140.	15.	19.9	154.	2.00	.797	.05	-.011
TERRAIN	10.	0.	1.0	168.	2.00	1.710	.05	.023
TERRAIN	140.	0.	1.0	168.	2.00	.483	.05	.020

Station ID : 13889
Years : 84 85 86 87 88
Start Date : January 1
Start Time : Midnight

RUN ID : JACKSONVILLE/INT'L ARPT

End Date : December 31
End Time : 11 PM

Frequency Distribution
(Count)

Wind Direction (Blowing From) / Stability Classes

	A	B	C	D	E	F	Total
N	19	106	240	1142	281	282	2070
NNE	13	79	211	1012	178	192	1685
NE	21	113	297	1638	304	224	2597
ENE	21	116	402	1142	234	240	2155
E	23	99	399	834	220	128	1703
ESE	23	144	432	817	167	104	1687
SE	21	146	458	1122	423	344	2514
SSE	23	138	187	560	312	406	1626
S	37	160	244	635	305	418	1799
SSW	21	120	238	594	279	344	1596
SW	40	180	395	827	410	480	2332
WSW	42	208	353	791	356	535	2285
W	44	227	395	771	363	651	2451
WNW	33	219	415	981	279	508	2435
NW	29	184	394	1131	363	493	2594
NNW	20	107	188	853	299	284	1751
Total	430	2346	5248	14850	4773	5633	43848

Frequency of Calm Winds : 10568
Average Wind Speed : 7.46 Knots

Station ID : 13889
Years : 84 85 86 87 88
Start Date : January 1
Start Time : Midnight

RUN ID : JACKSONVILLE/INT'L ARPT

End Date : December 31
End Time : 11 PM

Frequency Distribution
(Normalized)

Wind Direction (Blowing From) / Stability Classes

	A	B	C	D	E	F	Total
N	0.000433	0.002417	0.005473	0.026045	0.006409	0.006431	0.047209
NNE	0.000296	0.001802	0.004812	0.023080	0.004059	0.004379	0.038428
NE	0.000479	0.002577	0.006773	0.037356	0.006933	0.005109	0.059227
ENE	0.000479	0.002646	0.009168	0.026045	0.005337	0.005473	0.049147
E	0.000525	0.002258	0.009100	0.019020	0.005017	0.002919	0.038839
ESE	0.000525	0.003284	0.009852	0.018633	0.003809	0.002372	0.038474
SE	0.000479	0.003330	0.010445	0.025588	0.009647	0.007845	0.057334
SSE	0.000525	0.003147	0.004265	0.012771	0.007115	0.009259	0.037083
S	0.000844	0.003649	0.005565	0.014482	0.006956	0.009533	0.041028
SSW	0.000479	0.002737	0.005428	0.013547	0.006363	0.007845	0.036398
SW	0.000912	0.004105	0.009008	0.018861	0.009350	0.010947	0.053184
WSW	0.000958	0.004744	0.008051	0.018040	0.008119	0.012201	0.052112
W	0.001003	0.005177	0.009008	0.017583	0.008279	0.014847	0.055898
WNW	0.000753	0.004995	0.009465	0.022373	0.006363	0.011585	0.055533
NW	0.000661	0.004196	0.008986	0.025794	0.008279	0.011243	0.059159
NNW	0.000456	0.002440	0.004288	0.019454	0.006819	0.006477	0.039933
Total	0.009807	0.053503	0.119686	0.338670	0.108853	0.128467	

Frequency of Calm Winds : 24.10%
Average Wind Speed : 7.46 Knots

Attachment 7

(Regional Haze Calculation Spreadsheet)

JEA - Brandy Branch
Regional Haze Analysis — Wolf Island

Calculation of Extinction per year of Maximum Impact — 03/22/1999 11:40 AM — Last Revised 03/22/1999

Background Visibility 65.0 km
Background Extinction 0.06018 1/km

Table 1

Scenario Name	Actual 24-hr Impact (ug/m^3)	Date (yr/mo/dy/hr)	x Coordinate	y Coordinate	NO2 Impact (ug/m^3)	NO3 Impact (ug/m^3)	NH4NO3 (ug/m^3)	Minimum Daily Relative Humidity (%)	Maximum Daily Relative Humidity (%)	Average Daily Relative Humidity (%)	Estimate Relative Humidity Factor	NH4NO3 Source Extinction (1/km)
NOx												
1984 SNG1	0.180	84010624	470425.5	3465472.6	0.18000	0.24300	0.31347	29	79	54.0	1.45	0.00136
1985 SNG1	0.110	85070224	470425.5	3465472.6	0.11000	0.14850	0.19157	34	87	60.5	1.65	0.00095
1986 SNG1	0.090	86071124	470425.5	3465472.6	0.09000	0.12150	0.15674	38	82	60.0	1.60	0.00075
1987 SNG1	0.110	87090824	470425.5	3465472.6	0.11000	0.14850	0.19157	45	97	71.0	2.40	0.00138
1988 SNG1	0.100	88052324	470425.5	3465472.6	0.10000	0.13500	0.17415	32	87	59.5	1.60	0.00084

Scenario Name	Actual 24-hr Impact (ug/m^3)	Date (yr/mo/dy/hr)	x Coordinate	y Coordinate	SO2 Impact (ug/m^3)	SO4 Impact (ug/m^3)	(NH4)2SO4 (ug/m^3)	Minimum Daily Relative Humidity (%)	Maximum Daily Relative Humidity (%)	Average Daily Relative Humidity (%)	Estimate Relative Humidity Factor	(NH4)2SO4 Source Extinction (1/km)
SO2												
1984 SNG1	0.003	84010624	470425.5	3465472.6	0.00300	0.00450	0.00619	29	79	54.0	1.45	0.00003
1985 SNG1	0.001	85070224	470425.5	3465472.6	0.00100	0.00150	0.00206	34	87	60.5	1.65	0.00001
1986 SNG1	0.001	86071124	470425.5	3465472.6	0.00100	0.00150	0.00206	38	82	60.0	1.60	0.00001
1987 SNG1	0.002	87090824	470425.5	3465472.6	0.00200	0.00300	0.00413	45	97	71.0	2.40	0.00003
1988 SNG1	0.001	88052324	470425.5	3465472.6	0.00100	0.00150	0.00206	32	87	59.5	1.60	0.00001

Scenario Name	Actual 24-hr Impact (ug/m^3)	x Coordinate	y Coordinate	PM Source Extinction (1/km)
PM				
1984 SNG1	0.020	470425.5	3465472.6	0.00006
1985 SNG1	0.010	470425.5	3465472.6	0.00003
1986 SNG1	0.010	470425.5	3465472.6	0.00003
1987 SNG1	0.010	470425.5	3465472.6	0.00003
1988 SNG1	0.010	470425.5	3465472.6	0.00003

	Total Source Change in Extinction (%)	Pass/Fail 5.00% Change
1984	2.41	PASS
1985	1.64	PASS
1986	1.32	PASS
1987	2.39	PASS
1988	1.46	PASS

reghaze4

Jacksonville Electric Authority
Brandy Branch Facility

Construction Permit Application

May 1999

BLACK & VEATCH

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Attachments

Facility

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Combustion Turbines

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I. Application Information

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Jacksonville Electric Authority	
2. Site Name : Brandy Branch Facility	
3. Facility Identification Number :	[X] Unknown
4. Facility Location : Jacksonville Electric Authority - Brandy Branch Facility Street Address or Other Locator : City : Baldwin City County : Duval Zip Code : 32234	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Rec'd 19 May 1999
Airs ID - 0310485-001-AC
PSD-FL-267

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Name: Walter P. Bussells Title: Managing Director and Chief Executive Officer
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: 904-665-7220 Fax: 904-665-7366
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.* Signature ______ Date 7/3/95

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Unit 1 - 170 MW Simple Cycle Combustion Turbine	NA
002	Unit 2 - 170 MW Simple Cycle Combustion Turbine	NA
003	Unit 3 - 170 MW Simple Cycle Combustion Turbine	NA
004	Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)	
005	Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)	
006	Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)	

Purpose of Application and Category

ategory I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, .A.C.

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.

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.

Operation permit to be revised :

Reason for revision :

ategory II : All Air Operation Permit Applications Subject to Processing Under Rule 2-210.300(2)(b), F.A.C.

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 Fule 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.

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 :
NA

[ ] 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 : $7500.00 [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : JEA proposes to construct three 170 MW natural gas (NG) and NO. 2 fuel oil (FO) fired simple cycle combustion turbines (SCCTs) at the new electrical generating facility located near Baldwin City, Florida. The proposed SCCTs will be used for peaking power. The SCCTs proposed from this project are General Electric PG7241 FA (GE PG7241 FA).	
2. Projected or Actual Date of Commencement of Construction :	01-Oct-1999
3. Projected Date of Completion of Construction :	01-May-2001

Professional Engineer Certification

1. Professional Engineer Name : Anthony L. Compaan Registration Number : PE-0045662	
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Street Address : JEA - 21 W. Church St., T-10 City : Jacksonville	State : FL Zip Code : 32202-3139
3. Professional Engineer Telephone Numbers : Telephone : (904)665-7867	Fax : (904)665-7263

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 pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

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

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

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

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions 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.

Anthony L. Compaan
Signature
(seal)

May 7, 1999
Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact : Name : N. Bert Gianazza, P.E. Title : Environmental Health & Safety Group
2. Application Contact Mailing Address : Organization/Firm : Jacksonville Electric Authority Street Address : 21 West Church Street City : Jacksonville State : FL Zip Code : 32202-3139
3. Application Contact Telephone Numbers : Telephone : (904)665-6247 Fax : (904)665-7376

Application Comment

II. Facility Information

General Facility Information

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

1. Facility UTM Coordinates : Zone : 17 East (km) : 408.81 North (km) : 3354.38			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 30 19 14 Longitude (DD/MM/SS) : 81 56 55			
3. Governmental Facility Code : 0	4. Facility Status Code : C	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) : 4911
7. Facility Comment : Construction of new emission sources at a new power generating facility.			

Facility Contact

1. Name and Title of Facility Contact : N. Bert Gianazza, P.E. Environmental Health & Safety Group
2. Facility Contact Mailing Address : Organization/Firm : Jacksonville Electric Authority Street Address : 21 West Church Street City : Jacksonville State : FL Zip Code : 32202-3139
3. Facility Contact Telephone Numbers : Telephone : (904)665-6247 Fax : (904)665-7376

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	N
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment :	

Facility Regulations

B. FACILITY REGULATIONS

Rule Applicability Analysis

This facility is subject to preconstruction reivew for stationary sources (Chpt. 62-212 FAC). Rule 62-212.400 requires the following: Sources subject to the Prevention of Significant Deterioration (PSD)

B. FACILITY REGULATIONS

List of Applicable Regulations

Facility Pollutants

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
NOX	A
CO	A
VOC	A
SO2	A
PM	A
PM10	A
SAM	SM

Facility Supplemental Information

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Attachment A
2. Facility Plot Plan :	Attachment B
3. Process Flow Diagram(s) :	Attachment C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	Attachment E
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Applica	Attachment F

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt
8. List of Equipment/Activities Regulated under
9. Alternative Methods of Operation :
10. Alternative Modes of Operation (Emissions
11. Identification of Additional Applicable
12. Compliance Assurance Monitoring Plan :
13. Risk Management Plan Verification :
14. Compliance Report and Plan :
15. Compliance Certification (Hard-copy Require

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

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 : Unit 1 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 001 [ ] No Corresponding ID [ ] Unknown		
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 : This emission unit will be a GE PG7241 FA combustion turbine. Unit information throughout application is based on baseload, ISO conditions (59F). Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing the use of dry low NOx burner technology to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

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

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	01-May-2001
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : GE PG7241 FA
4. Generator Nameplate Rating : 170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1736	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum heat input (MBtu/h): Natural Gas firing @ 20F, 100% load = 1,736.3 LHV Fuel Oil firing @ 20F, 100% load = 1,934.7 LHV		

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)

Emissions Unit Information Section ___1___
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC). Rule 62-212.400 Prevention of Significant Deterioration (PSD)

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-1		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) N/A - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	90	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	999	°F
9. Actual Volumetric Flow Rate :	999999	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.835 North (km) : 3354.491		
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect worst-case low load and natural gas operation. Temp = 1,081F Flow = 1,623,767 acfm		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.87	5. Maximum Annual Rate : 7,480.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 869	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1622.9 Mbtu/h)/(1 lb/20,675 Btu)/(23.8 ft^3/lb)=1.87 Mscf/h (1.87 Mscf/h)x(4000 h/yr)=7,480 Mscf/yr (20675 Btu/lb)x(1 lb/23.8 ft^3)=868.7 Mbtu/Mscf	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.79	5. Maximum Annual Rate : 11,835.10
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 131	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1934.7 Mbtu/h)/(1 lb/18550 Btu)/(gal/ 7.05 lb)=14.79 1000 gal/h (14790 gal/h)x(800 h/yr)=11835.1 1000 gal/yr (18550)x(7.05)/(1000)=130.8 Btu/1000 gal	

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			EL
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			EL
8 - SAM			NS
9 - H095			NS
10 - H021			NS
11 - H015			NS
12 - H114			NS

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
318.0000000 lb/hour 285.6000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 79.2 lb/h
Fuel Oil = 318 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(79.2 lb/h x 4,000 h/yr) + (318 lb/h x 800 h/yr)] / (2,000 lb/ton) = 285.60 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	12.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	84.80	lb/hour	169.60	tons/year
5. Method of Compliance : CEM - 30 day rolling average or acceptable alternative.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	338.00	lb/hour	135.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppm@15%O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of performance for Stationary Gas Turbines NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332(a)(1)		

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

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
65.0000000 lb/hour 122.0000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 48 lb/h
Fuel Oil = 65 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(48 lb/h x 4,000 h/yr) + (65 lb/h x 800 h/yr)] / (2,000 lb/ton) = 122.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	15.00	ppm		
4. Equivalent Allowable Emissions :	52.00	lb/hour	104.00	tons/year
5. Method of Compliance : Method 10				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/r operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	26.00	ppm		
4. Equivalent Allowable Emissions :	74.00	lb/hour	29.60	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **VOC**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
3.0000000 lb/hour 6.8000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 2.8 lb/h
Fuel Oil = 3 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(2.8 lb/h x 4,000 h/yr) + (3 lb/h x 800 h/yr)] / (2,000 lb/ton) = 6.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	6.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 98.2100000 lb/hour	41.4200000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 1.07 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 98.21 lb/h (0.05% Sulfur) Potential hour of operation: Natural Gas = 4,000 h/yr Fuel Oil = 800 h/yr Potential annual emissions: [(1.07 lb/h x 4,000 h/yr) + (98.21 lb/h x 800 h/yr)] / (2,000 lb/ton) = 41.42 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	2.28	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	104.30	lb/h		
4. Equivalent Allowable Emissions :	104.30	lb/hour	41.72	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.		

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**		
2. Total Percent Efficiency of Control :	%	
3. Potential Emissions :	17.0000000 lb/hour	24.8000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions:	to	tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :	
7. Emissions Method Code : 0		

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

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

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :		
2. Basis for Allowable Opacity :	OTHER	
3. Requested Allowable Opacity :		
Normal Conditions :	10	%
Exceptional Conditions :	100	%
Maximum Period of Excess Opacity Allowed :	6	min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity		
5. Visible Emissions Comment : Two-hour rule for startup and shutdown (62-210.700)		

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity.
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 2
:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Natural gas flow monitoring will be operated pursuant to 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[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?

[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, 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	SO2 : C	NO2 : C		
4. Baseline Emissions :				
PM :	0.0000	lb/hour	0.0000	tons/year
SO2 :	0.0000	lb/hour	0.0000	tons/year
NO2 :			0.0000	tons/year
5. PSD Comment :				

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

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.

Emissions Unit Information Section 2

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 2 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 002 [ ] No Corresponding ID [ ] Unknown		
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 : This emission unit will be a GE PG7241 FA combustion turbine. Unit information throughout application is based on baseload, ISO conditions (59F). Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing the use of dry low NOx burner technology to control NOx emissions.
2. Control Device or Method Code : 25

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

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

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	01-May-2001
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : GE PG7241 FA
4. Generator Nameplate Rating : 170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1736 mmBtu/hr	
2. Maximum Incinerator Rate : lb/hr	tons/day
3. Maximum Process or Throughput Rate :	
4. Maximum Production Rate :	
5. Operating Capacity Comment : The maximum heat input (MBtu/h): Natural Gas firing @ 20F, 100% load = 1,736.3 LHV Fuel Oil firing @ 20F, 100% load = 1,934.7 LHV	

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)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC). Rule 62-212.400 Prevention of Significant Deterioration (PSD)

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-2		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) N/A - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	90	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	999	°F
9. Actual Volumetric Flow Rate :	999999	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.774	North (km) : 3354.491	
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect worst-case low load and natural gas operation. Temp = 1,081F Flow = 1,623,767 acfm		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.87	5. Maximum Annual Rate : 7,480.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 869	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1622.9 Mbtu/h)/(1 lb/20,675 Btu)/(23.8 ft^3/lb)=1.87 Mscf/h (1.87 Mscf/h)x(4000 h/yr)=7,480 Mscf/yr (20675 Btu/lb)x(1 lb/23.8 ft^3)=868.7 Mbtu/Mscf	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.79	5. Maximum Annual Rate : 11,835.10
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 131	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1934.7 Mbtu/h)/(1 lb/18550 Btu)/(gal/ 7.05 lb)=14.79 1000 gal/h (14790 gal/h)x(800 h/yr)=11835.1 1000 gal/yr (18550)x(7.05)/(1000)=130.8 Btu/1000 gal	

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			EL
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			EL
8 - SAM			NS
9 - H095			NS
10 - H021			NS
11 - H015			NS
12 - H114			NS

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

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
318.0000000 lb/hour 285.6000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 79.2 lb/h
Fuel Oil = 318 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(99 lb/h x 4,000 h/yr) + (318 lb/h x 800 h/yr)] / (2,000 lb/ton) = 285.6 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	12.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	84.80	lb/hour	169.60	tons/year
5. Method of Compliance : CEM - 30 day rolling average or acceptable alternative.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	338.00	lb/hour	135.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppm@15%O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of performance for Stationary Gas Turbines NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332(a)(1)		

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

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
65.0000000 lb/hour 122.0000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 48 lb/h
Fuel Oil = 65 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(48 lb/h x 4,000 h/yr) + (65 lb/h x 800 h/yr)] / (2,000 lb/ton) = 122.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	15.00	ppm		
4. Equivalent Allowable Emissions :	52.00	lb/hour	104.00	tons/year
5. Method of Compliance : Method 10				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/r operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	26.00	ppm		
4. Equivalent Allowable Emissions :	74.00	lb/hour	29.60	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **VOC**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
3.0000000 lb/hour 6.8000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 2.8 lb/h
Fuel Oil = 3 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(2.8 lb/h x 4,000 h/yr) + (3 lb/h x 800 h/yr)] / (2,000 lb/ton) = 6.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	6.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
98.2100000 lb/hour 41.4200000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 1.07 lb/h (0.2 gr Sulfur/100 scf)
Fuel Oil = 98.21 lb/h (0.05% Sulfur)

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(1.07 lb/h x 4,000 h/yr) + (98.21 lb/h x 800 h/yr)] / (2,000 lb/ton) = 41.42 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		1.14	lb/h	
4. Equivalent Allowable Emissions :	1.14	lb/hour	2.28	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	104.30	lb/h		
4. Equivalent Allowable Emissions :	104.30	lb/hour	41.72	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.		

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		9.00	lb/h	
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

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Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units : 9.00 lb/h	
4. Equivalent Allowable Emissions : 9.00 lb/hour 18.00 tons/year	
5. Method of Compliance : Method 9	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY	

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :			
2. Basis for Allowable Opacity :	OTHER		
3. Requested Allowable Opacity :			
	Normal Conditions :	10	%
	Exceptional Conditions :	100	%
	Maximum Period of Excess Opacity Allowed :	6	min/hour
4. Method of Compliance :			
USEPA Method 9 - Visual Determination of Opacity			
5. Visible Emissions Comment :			
Two hour rule startup / shutdown 62-210.700			

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :		
2. Basis for Allowable Opacity : RULE		
3. Requested Allowable Opacity :		
Normal Conditions :	20	%
Exceptional Conditions :		%
Maximum Period of Excess Opacity Allowed :		min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity.		
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard		

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 2
:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Natural gas flow monitoring will be operated pursuant to 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[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?

[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, 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	SO2 :	C	NO2 :	C
4. Baseline Emissions :					
PM :	0.0000	lb/hour		0.0000	tons/year
SO2 :	0.0000	lb/hour		0.0000	tons/year
NO2 :				0.0000	tons/year
5. PSD Comment :					

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

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.

Emissions Unit Information Section 3

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 3 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 003 [ ] No Corresponding ID [ ] Unknown		
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 : This emission unit will be a GE PG7241 FA combustion turbine. Unit information throughout application is based on baseload, ISO conditions (59F). Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing the use of dry low NOx burner technology to control NOx emissions.
2. Control Device or Method Code : 25

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	01-May-2001	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : General Electric		Model Number : GE PG7241 FA
4. Generator Nameplate Rating :	170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	1736	mmBtu/hr	
2. Maximum Incinerator Rate :		lb/hr	tons/day
3. Maximum Process or Throughput Rate :			
4. Maximum Production Rate :			
5. Operating Capacity Comment : The maximum heat input (MBtu/h): Natural Gas firing @ 20F, 100% load = 1,736.3 LHV Fuel Oil firing @ 20F, 100% load = 1,934.7 LHV			

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)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC). Rule 62-212.400 Prevention of Significant Deterioration

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-3		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) N/A - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	90	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	999	°F
9. Actual Volumetric Flow Rate :	999999	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.713 North (km) : 3354.491		
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect worst-case low load and natural gas operation. Temp = 1,081F Flow = 1,623,767 acfm		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.87	5. Maximum Annual Rate : 7,480.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 869	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1622.9 Mbtu/h)/(1 lb/20,675 Btu)/(23.8 ft^3/lb)=1.87 Mscf/h (1.87 Mscf/h)x(4000 h/yr)=7,480 Mscf/yr (20675 Btu/lb)x(1 lb/23.8 ft^3)=868.7 Mbtu/Mscf	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.79	5. Maximum Annual Rate : 11,832.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 131	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1934.7 Mbtu/h)/(1 lb/18550 Btu)/(gal/ 7.05 lb)=14.79 1000 gal/h (14790 gal/h)x(400 h/yr)=5917.53 1000 gal/yr (18550)x(7.05)/(1000)=130.8 Btu/1000 gal	

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			EL
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			EL
8 - SAM			NS
9 - H095			NS
10 - H021			NS
11 - H015			NS
12 - H114			NS

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

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 318.0000000 lb/hour	285.6000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 79.2 lb/h Fuel Oil = 318 lb/h Potential hour of operation: Natural Gas = 4,000 h/yr Fuel Oil = 800 h/yr Potential annual emissions: [(79.2 lb/h x 4,000 h/yr) + (318 lb/h x 800 h/yr)] / (2,000 lb/ton) = 285.6 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	12.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	84.80	lb/hour	169.60	tons/year
5. Method of Compliance : CEM - 30 day rolling average or acceptable alternative.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	338.00	lb/hour	135.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppm@15%O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of performance for Stationary Gas Turbines NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332(a)(1)		

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

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
65.0000000 lb/hour 122.0000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 48 lb/h
Fuel Oil = 65 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(48 lb/h x 4,000 h/yr) + (65 lb/h x 800 h/yr)] / (2,000 lb/ton) = 122 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	15.00	ppm		
4. Equivalent Allowable Emissions :	52.00	lb/hour	104.00	tons/year
5. Method of Compliance : Method 10				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/r operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	26.00	ppm		
4. Equivalent Allowable Emissions :	74.00	lb/hour	29.60	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **VOC**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 3.0000000 lb/hour	6.8000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 2.8 lb/h Fuel Oil = 3 lb/h Potential hour of operation: Natural Gas = 4,000 h/yr Fuel Oil = 800 h/yr Potential annual emissions: [(2.8 lb/h x 4,000 h/yr) + (3 lb/h x 800 h/yr)] / (2,000 lb/ton) = 6.8 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		1.40	ppm	
4. Equivalent Allowable Emissions :	3.00	lb/hour	6.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 98.2100000 lb/hour	41.4200000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions:	to tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 1.07 lb/h (0.2 gr Sulfur/100 scf)
Fuel Oil = 98.21 lb/h (0.05% Sulfur)

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(1.07 lb/h x 4,000 h/yr) + (98.21 lb/h x 800 h/yr)] / (2,000 lb/ton) = 41.42 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	2.28	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		104.30	lb/h	
4. Equivalent Allowable Emissions :	104.30	lb/hour	41.72	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.		

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

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
   17.0000000 lb/hour 24.8000000 tons/year

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

5. Range of Estimated Fugitive/Other Emissions:
   to tons/year

6. Emissions Factor Units :
   Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

   Highest hourly emissions for simple cycle operation:
   Natural Gas = 9.0 lb/h
   Fuel Oil = 17.0 lb/h

   Potential hour of operation:
   Natural Gas = 4,000 h/yr
   Fuel Oil = 800 h/yr

   Potential annual emissions:
   [(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		9.00	lb/h	
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		17.00	lb/h	
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 17.0000000 lb/hour	24.8000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

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

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : OTHER
3. Requested Allowable Opacity : Normal Conditions : 10 % Exceptional Conditions : 100 % Maximum Period of Excess Opacity Allowed : 6 min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment : Two-hour rule. Startup / shutdown 62-210.700

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :	
2. Basis for Allowable Opacity :	RULE
3. Requested Allowable Opacity : Normal Conditions :	20 %
Exceptional Conditions :	%
Maximum Period of Excess Opacity Allowed :	min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity.	
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 2
:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Natural gas flow monitoring will be operated pursuant to 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[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?

[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, 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	SO2 : C	NO2 : C	
4. Baseline Emissions :				
	PM :	0.0000 lb/hour	0.0000 tons/year	
	SO2 :	0.0000 lb/hour	0.0000 tons/year	
	NO2 :		0.0000 tons/year	
5. PSD Comment :				

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

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

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

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

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

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

[X] 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.

Emissions Unit Information Section 4

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)		
2. Emissions Unit Identification Number : 004 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines on the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a vertical fixed roof design.		

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Emissions Unit Control Equipment

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

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-4		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emission resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :	40	feet
7. Exit Diameter :	0.0	feet
8. Exit Temperature :	59	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm

12. Nonstack Emission Point Height :		40 feet		
13. Emission Point UTM Coordinates :				
Zone : 17	East (km) :	408.934	North (km) :	3354.448
14. Emission Point Comment :				

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : #2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301019	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor	

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

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
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 : As specified in 40 CFR 60.116(a) and (b), Subpart kb.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Rule: 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] 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?

[ ] 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, 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 :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment P
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

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

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

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

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

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

[X] 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.

Emissions Unit Information Section 5

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)		
2. Emissions Unit Identification Number : 005 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines on the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a vertical fixed roof design.		

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Emissions Unit Control Equipment

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

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-5		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emission resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :	40	feet
7. Exit Diameter :	0.0	feet
8. Exit Temperature :	59	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm

12. Nonstack Emission Point Height :	40 feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.934 North (km) : 3354.415	
14. Emission Point Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : #2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301019	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor	

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

Emissions Unit Information Section 5
Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] 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?

[ ] 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, 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 :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment P
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

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

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

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

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

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

[X] 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.

Emissions Unit Information Section 6

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)		
2. Emissions Unit Identification Number : 006 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines on the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a vertical fixed roof design.		

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Emissions Unit Control Equipment

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

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	S-6	
2. Emission Point Type Code :	1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emission resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :	40	feet
7. Exit Diameter :	0.0	feet
8. Exit Temperature :	59	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm

12. Nonstack Emission Point Height :				40 feet	
13. Emission Point UTM Coordinates :					
Zone :	17	East (km) :	408.910	North (km) :	3354.414
14. Emission Point Comment :					

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : #2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301019	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor	

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

Emissions Unit Information Section 6
Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] 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?

[ ] 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, 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 :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment P
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

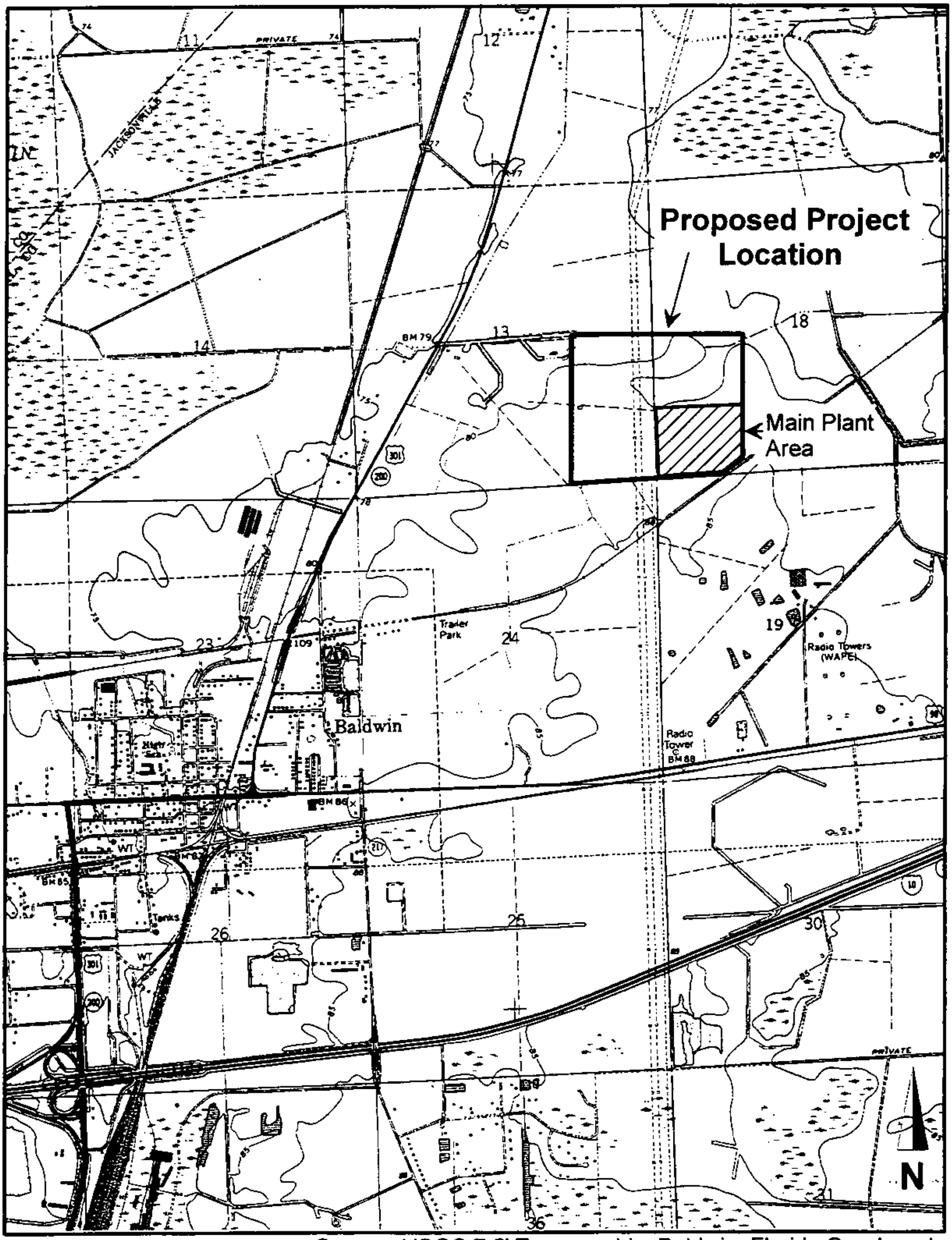
10. Alternative Methods of Operations :
11. Altemtive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

Attachment A

Attachment A

Area Map Showing Facility Location



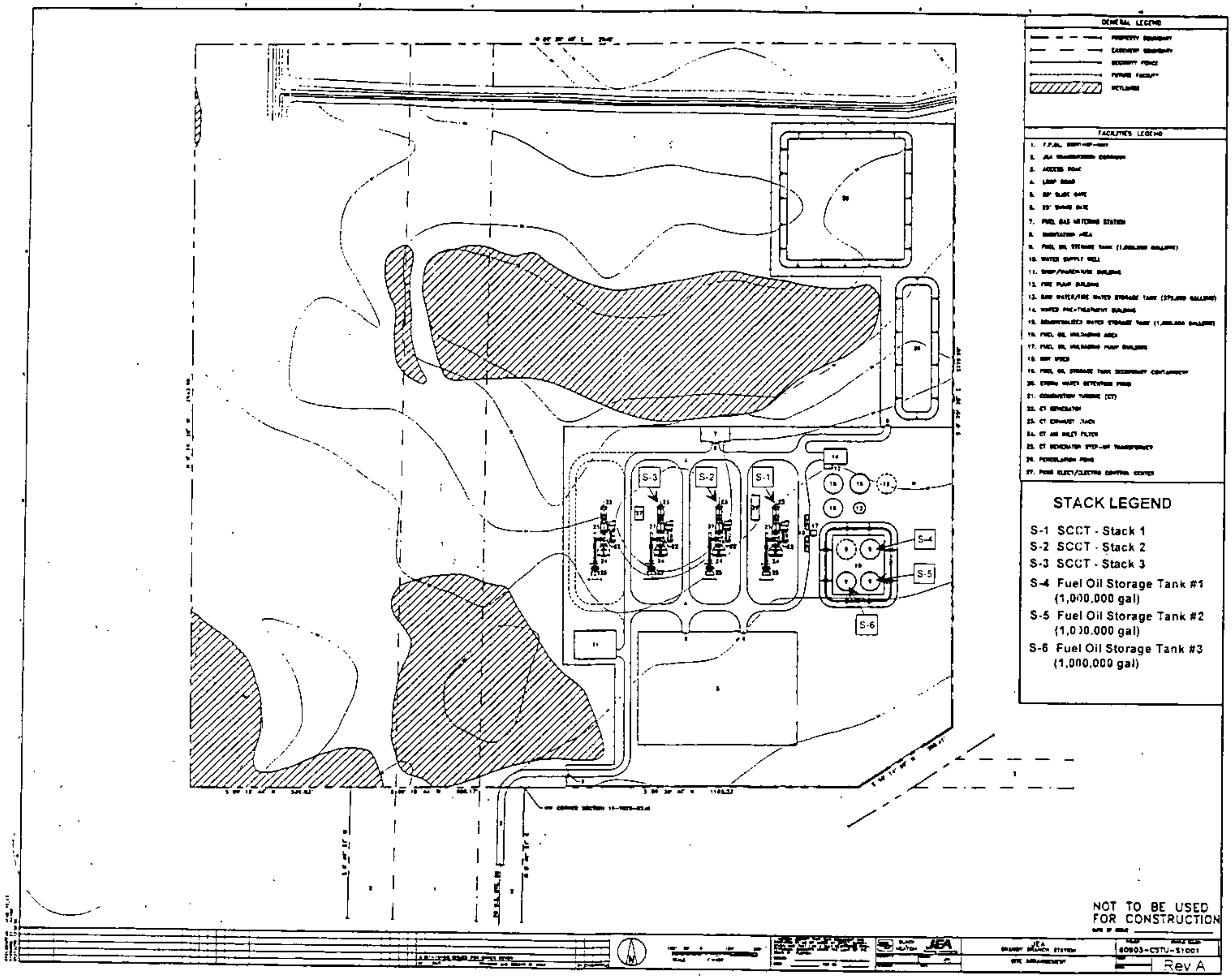
Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Attachment B

Attachment B

Facility Plot Plan



JEASTACK SRF

Attachment C

Attachment C

Process Flow Diagrams
(See individual unit process flow diagrams, Attachments H, and P)

Attachment D

Attachment D

Facility Applicable Requirements

Facility Applicable Requirements

Applicable Regulation	Applicable Requirement
40 CFR 60.7, Notification and recordkeeping	Any physical or operational change to an existing facility which may increase the emission of any air pollutant requires notification pursuant to this rule, postmarked 60 days before the change is commenced.
	An excess emissions and monitoring systems performance report shall be submitted semiannually. The facility shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the facility; any malfunction of the air pollution control equipment; or any period the CEMS is inoperable.
	The owner or operator of an affected facility shall maintain a file of CEMS and performance test measurements, evaluations, and calibration checks for two years following the date of such activity.
40 CFR 60.8 (d), Testing	Notify the Administrator of any performance test at least 30 days prior to the test.
40 CFR 60.8 (e), Testing	Provide sampling ports, safe sampling platform, utilities and testing equipment prior to stack test.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 61.5, Prohibited activities	Ninety days after the effective date of any standard pursuant to this part, no owner or operator shall operate any existing source subject to that standard in violation of the standard.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 72.90, Annual compliance certification report	Sixty days after the end of the calendar year, the designated representative shall submit an annual compliance certification report for each affected unit.

Applicable Regulation	Applicable Requirement
40 CFR 75.3, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
F.A.C. 62-4.030, General Prohibition	Any stationary installation which will be a source of air pollution shall not be operated, maintained, constructed, expanded, or modified without appropriate and valid permits issued by the DEP.
F.A.C. 62-4.090, Renewals	Submit an operating permit renewal application to the FDEP 180 days before the expiration of the operating permit.
F.A.C. 62-4.130, Plant Operation - Problems	If a facility is temporarily unable to comply with any of the conditions of a permit due to breakdown of equipment or destruction by hazard of fire, wind, or by other cause, the permittee shall immediately notify the DEP.
F.A.C. 62-4.160, Permit Conditions	The permittee shall allow authorized DEP personnel access to the facility where the permitted activity is located to have access to and copy any records that must be kept under conditions of the permit; inspect the facility, equipment, practices, or operations regulated or required under the permit; and sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with permit conditions.
	Permits, or a copy thereof, shall be kept at the work site of the permitted activity.
	The permittee shall furnish all records and plans required under DEP rules; hold at the facility all monitoring information, reports, and records of data for at least three years from the date of the sample, measurement, report, or application.
F.A.C. 62-4.160, Permit Conditions (continued)	When requested by DEP, the permittee shall furnish, within a reasonable time, any information required by law which is needed to determine compliance with any permit.

Applicable Regulation	Applicable Requirement
F.A.C. 62-4.210, Construction Permits	No person shall construct any installation or facility which will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the DEP unless exempted by statute or DEP rule.
F.A.C. 62-210.300, Permits Required	An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification
F.A.C. 62-210.350, Public Notice and Comment	A notice of proposed agency action on a permit application as described in F.A. C. 62-210.350(1)(a), where the proposed agency action is to issue the permit, shall be published by the applicant.
F.A.C. 62-210.360, Administrative Permit Corrections	A facility owner shall notify the DEP by letter of minor corrections to information contained in a permit. For operating permits, a copy shall be provided to the EPA.
F.A.C. 62-210.370, Reports	An Annual Operating Report for Air Pollution Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for all Title V sources. The annual operating report shall be submitted by March 1 of the following year.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting form malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-213.205, Annual Emissions Fee	Each Title V source must pay an annual emissions fee between January 15 and March 1 based on the factors identified in this rule.
F.A.C. 62-213.420, Permit Applications	Each Title V Acid Rain source that commenced operation on or before October 25, 1995 shall submit an operating permit application by June 15, 1996.
F.A.C. 62-214.320, Applications	New acid rain sources must submit an Acid Rain Part application in accordance with the provisions of 40 CFR Part 72.
F.A.C. 62-273.400, Air Pollution Episodes	Upon a declaration that an air pollution episode level exists (alert, warning, or emergency), any person responsible for the operation or conduct of activities which result in

Applicable Regulation	Applicable Requirement
	emission of air pollutants shall take actions as required in F.A.C. 62-273.400, 62-273.500, and 62-273.600.
F.A.C. 62-273.400, Air Alert	Upon a declaration of an air alert, open burning will be prohibited and motor vehicle operation minimized.
F.A.C. 62-273.500, Air Warning	Upon a declaration of an air warning, open burning will be prohibited and motor vehicle operation minimized. In addition, unnecessary space heating/cooling is prohibited.
F.A.C. 62-273.600, Air Emergency	Upon a declaration of an air emergency, operations will be restricted as prescribed under 62-273.600.
F.A.C. 62-296.320, General Pollutant Emission Limiting Standards	No person shall store, pump, handle, process, load, unload, or use in any process or installation, VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary by the DEP.
	No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
	Open burning in connection with industrial, commercial, or municipal operations is prohibited except if an emergency exists which requires immediate action to protect human health and safety.
	No person shall cause, let, permit, suffer, or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions.
	Each owner or operator of an emission unit subject to this rule shall install, calibrate, operate, and maintain a continuous monitoring system according to the requirements of 40 CFR 51, Appendix P and 40 CFR 60, Appendix B.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment E

Attachment E

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

As a result of the construction of the simple cycle combustion turbines and the associated equipment at the project site minimal quantities of unconfined particulate matter (fugitive dust) may be released tot he atmosphere. These anticipated construction activities might be generally broken down into three phases as they relate to generating fugitive dust: debris removal, site preparation, and general construction. Because the equipment are being installed at new facility, JEA proposes to utilize watering to control fugitive dust. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder maintaining soil moisture content or establishing a crust which prevents soil movement under windy conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. For the construction phase of the project, it is proposed that water be applied as necessary during high wind conditions when fugitive dust is evident beyond the property boundary. The water will be applied using on or a combination of several methods listed above.

Attachment F

Attachment F

Supplemental Information for Construction Permit Application

Supplemental Information for Construction Permit Application

Please refer to the Prevention of Significant Deterioration Air Permit Application for Jacksonville Electric Authority's Brandy Branch Facility.

Attachment G

Attachment G

Unit Specific Applicable Requirements

170 MW Simple Cycle Combustion Turbine
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).
40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: • For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. • For natural gas (no bulk storage), the values shall be determined andrecorded daily.
	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334(c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.

Applicable Regulations	Applicable Requirement
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibrations, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5(f).
40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NO_x continuous emission monitoring system (NO_x pollutant monitor and an O_2 or CO_2 diluent gas monitor) with automated DAHS which records NO_x concentration, O_2 or CO_2 concentration, and NO_x emission rate.
	The owner or operator shall measure CO_2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted

Applicable Regulations	Applicable Requirement
	according to the procedures in Appendix F of this subpart.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.
40 CFR 75.11, Specific provisions for monitoring SO_2	Gas and oiled fired units shall measure and record SO_2 emissions as specified in 40 CFR 75, Appendix D.
40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO_2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20(b) and (c).
	The owner or operator of a by-pass stack CEMS shall comply with all the requirements of 40 CFR 75.20 (a), (b), and (c) except only one nine-run relative accuracy test audit for certification or recertification of the flow monitor needs to be performed.
	The owner or operator using the optional SO_2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20(g).
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24(c) through (e), and repeat tests applicable to the "out-of-control" parameter.
40 CFR 75.30, SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.
40 CFR 75.51, SUBPART F	The owner or operator shall comply with the recordkeeping

Applicable Regulations	Applicable Requirement
- Recordkeeping Requirements, General recordkeeping provisions for specific situations	requirements of 40 CFR 75.51(c)(1) through (3) when combusting natural gas and fuel oil.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52(a)(1) through (3) and 40 CFR 75.52(a)(5) through (7).
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO_2 emission records, the owner or operator shall record information as required in 40 CFR 75.55(c) in lieu of the provisions of 40 CFR 75.54(c).
40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56(a)(1) through (3) and 40 CFR 75.56(a)(5) through (7).
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60(c) for any claims of confidential data.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this

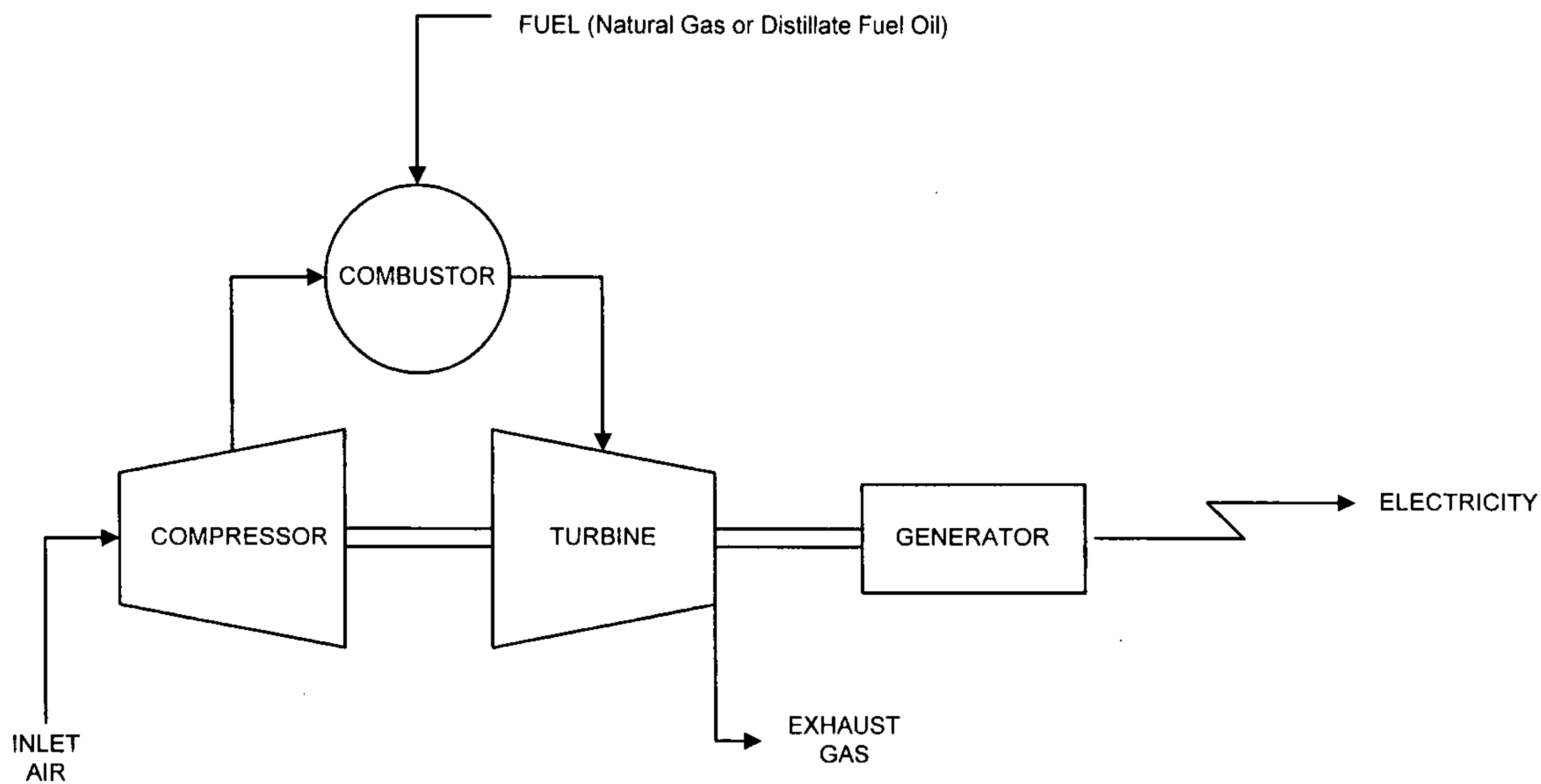
Applicable Regulations	Applicable Requirement
	section.
40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO_2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emissions rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment H

Attachment H

Process Flow Diagram

Jacksonville Electric Authority
Brandy Branch Facility
Facility ID: Unknown



Simple Cycle Combustion Turbine
Process Flow Diagram

Attachment I

Attachment I

Fuel Analysis or Specification

Fuel Analysis

Fuel is specified as pipeline quality sweet natural gas or No. 2 fuel oil containing no more than 0.05 percent sulfur.

Attachment J

Attachment J

Detailed Description of Control Equipment

Detailed Description of Control Equipment

1.) Low NO_x Burner: A technology that uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. this two-stage process ensures good mixing of the air and fuel, and minimizes the amount of air required which results in low NO_x emissions.

2.) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

3.) Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used only during oil firing.

Attachment K

Attachment K

Description of Stack Sampling Facilities

Stack Sampling Facilities

Vendors for these items have not yet been identified. A detailed description of the stack sampling facilities will be included with the operating permit application.

The stack sampling facilities will conform to F.A.C. Chapter 62-297.

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Stationary Sources - Emissions Monitoring

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62-297.100 Purpose and Scope.

The Department of Environmental Protection adopts this chapter to establish test procedures that shall be used to determine the compliance of air pollutant emissions units with emission limiting standards specified in or established pursuant to any of the stationary source rules of the Department. Words and phrases used in this chapter, unless clearly indicated otherwise, are defined at Rule 62-210.200, F.A.C.
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(a); Formerly 17-297.100; Amended 11-23-94, 3-13-96.

62-297.200 Definitions. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.100; Amended 6-29-93; Formerly 17-297.200; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.310 General Compliance Test Requirements.
The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air.

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

(2) Operating Rate During Testing. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity as defined below. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

(a) Combustion Turbines. (Reserved)

(b) All Other Sources. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

(3) Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

(4) Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

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

TABLE 297.310-1
CALIBRATION SCHEDULE

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

(5) Determination of Process Variables.

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

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

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

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

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

(c) Sampling Ports.

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

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

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

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

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

(d). Work Platforms.

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

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

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

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

(e). Access to Work Platform.

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

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

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

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

(g). Sampling Equipment Support.

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

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

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

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

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

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

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

(a) General Compliance Testing.

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

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions

unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

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

a Did not operate; or

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

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

a. Visible emissions, if there is an applicable standard;

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

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

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

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

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62- 210.300(4)(a)1. through 7., F.A.C.

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

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

(8) Test Reports.

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

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

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

1. The type, location, and designation of the emissions unit tested.

2. The facility at which the emissions unit is located.

3. The owner or operator of the emissions unit.

4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.

11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

l2. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.

14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.

16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(b); Formerly 17-297.310; Amended 11-23-94, 3-13-96, 10-28-97.

62-297.330 Applicable Test Procedures. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92, Formerly 17-297.330; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.340 Frequency of Compliance Tests. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(2); Formerly 17-297.340; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.345 Stack Sampling Facilities Provided by the Owner of an Emissions Unit. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(4), Formerly 17-297.345, Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.350 Determination of Process Variables. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(5), Formerly 17-297.350, Amended 11-23-94. Repealed 3-13-96.

62-297.400 EPA Methods Adopted by Reference. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(c), Formerly 17-297.400, Amended 11-23-94, Repealed 1-1-96.

62-297.401 Compliance Test Methods.

This rule adopts the test methods to be used where a compliance test is required by Department air pollution rule or air permit. The EPA test methods and quality assurance procedures listed in this rule and contained in 40 CFR Part 51, Appendix M, 40 CFR Part 60, Appendix A and F, 40 CFR Part 61, Appendix B and C and 40 CFR Part 63, Appendix A, are adopted and incorporated by reference in Rule 62-204.800, F.A.C. The EPA test methods that are adopted by reference in Rule 62-204.800, F.A.C., are adopted in their entirety except for those provisions referring to approval of alternative procedures by the Administrator. For purposes of this rule, such alternative procedures may only be approved by the Secretary or his or her designee in accordance with Rule 62-297.620, F.A.C.

(1)(a) EPA Method 1 -- Sample and Velocity Traverses for Stationary sources -- 40 CFR 60 Appendix A.

(b) EPA Method 1A -- Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts -- 40 CFR 60 Appendix A.

(2) EPA Method 2 -- Determination of Stack Gas Velocity and Volumetric Flow Rate -- 40 CFR 60 Appendix A.

(a) EPA Method 2A -- Direct Measurement of Gas Volume Through Pipes and Small Ducts -- 40 CFR 60 Appendix A.

(b) EPA Method 2B -- Determination of Exhaust Gas Volume Flow Rate from Gasoline Vapor Incinerators -- 40 CFR 60 Appendix A.

(c) EPA Method 2C -- Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks and Ducts (Standard Pitot Tube) -- 40 CFR 60 Appendix A

(d) EPA Method 2D -- Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts -- 40 CFR 60 Appendix A.

(3) EPA Method 3 -- Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight -- 40 CFR 60 Appendix A.

(a) EPA Method 3A -- Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A

(b) (Reserved).

(4) EPA Method 4 -- Determination of Moisture Content in Stack Gases -- 40 CFR 60 Appendix A.

(5) EPA Method 5 -- Determination of Particulate Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 5A -- Determination of Particulate Emissions from the Asphalt Processing and Asphalt Roofing Industry -- 40 CFR 60 Appendix A.

(b) EPA Method 5B -- Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(c) Reserved.

(d) EPA Method 5D -- Determination of Particulate Matter Emissions from Positive Pressure Fabric Filters -- 40 CFR 60 Appendix A.

(e) EPA Method 5E -- Determination of Particulate Emissions from the Wool Fiberglass Insulation Manufacturing Industry -- 40 CFR 60 Appendix A.

(f) EPA Method 5F -- Determination of Nonsulfate Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(g) EPA Method 5G -- Determination of Particulate Emissions from Wood Heaters from a Dilution Tunnel Sampling Location -- 40 CFR 60 Appendix A.

(h) EPA Method 5H -- Determination of Particulate Emissions from Wood Heaters from a Stack Location -- 40 CFR 60 Appendix A.

(6) EPA Method 6 -- Determination of Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 6A -- Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(b) EPA Method 6B -- Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(c) EPA Method 6C -- Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(7) EPA Method 7 -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 7A -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(b) EPA Method 7B -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Ultraviolet Spectrophotometry) -- 40 CFR 60 Appendix A.

(c) EPA Method 7C -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Colorimetric Method -- 40 CFR 60 Appendix A.

(d) EPA Method 7D -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(e) EPA Method 7E -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(8) EPA Method 8 -- Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(9)(a) EPA Method 9 -- Visual Determination of the Opacity of Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(b) Alternate Method 1 -- Determination of the Opacity of Emissions from Stationary Sources Remotely by Lidar -- 40 CFR 60 Appendix A.

(c) DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six- minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

(10) EPA Method 10 -- Determination of Carbon Monoxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 10A -- Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries -- 40 CFR 60 Appendix .

(b) EPA Method 10B -- Determination of Carbon Monoxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(11) EPA Method 11 -- Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries -- 40 CFR 60 Appendix A.

(12) EPA Method 12 -- Determination of Inorganic Lead Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(13) EPA Methods 13A and 13B.

(a) EPA Method 13A -- Determination of Total Fluoride Emissions from Stationary Sources -- SPADNS --- Zirconium Lake Method -- 40 CFR 60 Appendix A.

(b) EPA Method 13B -- Determination of Total Fluoride Emissions from Stationary Sources -- Specific Ion Electrode Method -- 40 CFR 60 Appendix A.

(14) EPA Method 14 -- Determination of Fluoride Emissions from Potroom Roof Monitors of Primary Aluminum Plants -- 40 CFR 60 Appendix A.

(15) EPA Method 15 -- Determination of Hydrogen Sulfide, Carbonyl Sulfide and Carbon Disulfide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 15A -- Determination of Total Reduced Sulfur Emissions from Sulfur Recovery Plants in Petroleum Refineries -- 40 CFR 60 Appendix A.

(16) EPA Method 16 -- Semicontinuous Determination of Sulfur Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 16A -- Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique) -- 40 CFR 60 Appendix A.

(b) EPA Method 16B -- Determination of Total Reduced Sulfur Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(17) EPA Method 17 -- Determination of Particulate Emissions from Stationary Sources (In-Stack Filtration Method) -- 40 CFR 60 Appendix A.

(18) EPA Method 18 -- Measurement of Gaseous Organic Compound Emissions by Gas Chromatography -- 40 CFR 60 Appendix A.

(19) EPA Method 19 -- Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates -- 40 CFR 60 Appendix A.

(20) EPA Method 20 -- Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines -- 40 CFR 60 Appendix A.

(21) EPA Method 21 -- Determination of Volatile Organic Compound Leaks -- 40 CFR 60 Appendix A.

(22) EPA Method 22 -- Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares -- 40 CFR 60 Appendix A.

(23) EPA Method 23 -- Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources -- 40 CFR 60 Appendix A.

(24) EPA Method 24 -- Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings -- 40 CFR 60 Appendix A.

(a) EPA Method 24A -- Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings -- 40 CFR 60 Appendix A.

(b) No change.

(25) EPA Method 25 -- Determination of Total Gaseous Nonmethane Organic Emissions as Carbon -- 40 CFR 60 Appendix A.

(a) EPA Method 25A -- Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer -- 40 CFR 60 Appendix A.

(b) EPA Method 25B -- Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer -- 40 CFR 60 Appendix A.

(26) EPA Method 26 -- Determination of Hydrogen Chloride Emissions From Stationary Sources -- 40 CFR 60, Appendix A.

(a) EPA Method 26A -- Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources - Isokinetic Method -- 40 CFR 60, Appendix A

(27) EPA Method 27 -- Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test -- 40 CFR 60 Appendix A.

(28) EPA Method 28 -- Certification and Auditing of Wood Heaters -- 40 CFR 60 Appendix A.

(a) EPA Method 28A -- Measurement of Air to Fuel Ratio and Minimum Achievable Burn Rates for Wood-Fired Appliances -- 40 CFR 60 Appendix A.

(29) EPA Method 29 -- Determination of Metals Emission from Stationary Sources -- 40 CFR 60 Appendix A.

(30) Reserved.

(31) 40 CFR 60 Appendix F -- Quality Assurance Procedures -- .

(32) EPA Method 101 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Air Streams -- 40 CFR 61 Appendix B.

(a) EPA Method 101A -- Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators -- 40 CFR 61 Appendix B.

(33) EPA Method 102 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Hydrogen Streams -- 40 CFR 61 Appendix B.

(34) EPA Method 103 -- Beryllium Screening Method -- 40 CFR 61 Appendix B.

(35) EPA Method 104 -- Determination of Beryllium Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(36) EPA Method 105 -- Determination of Mercury in Wastewater Treatment Plant Sewage Sludges -- 40 CFR 61 Appendix B.

(37) EPA Method 106 -- Determination of Vinyl Chloride Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(38) EPA Method 107 -- Determination of Vinyl Chloride Content of Inprocess Wastewater Samples, and Vinyl Chloride Content of Polyvinyl Chloride Resin, Slurry, Wet Cake, and Latex Samples -- 40 CFR 61 Appendix B.

(a) EPA Method 107A -- Determination of Vinyl Chloride Content of Solvents, Resin-Solvent Solution, Polyvinyl Chloride Resin, Resin Slurry, Wet Resin, and Latex Samples -- 40 CFR 61 Appendix B.

(39) EPA Method 108 -- Determination of Particulate and Gaseous Arsenic Emissions -- 40 CFR 61 Appendix B.

(a) EPA Method 108A -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(b) EPA Method 108B -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(c) EPA Method 108C -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(40) 40 CFR 61 Appendix C -- Quality Assurance Procedures.

(41) EPA Method 201 -- Determination of PM_{10} Emissions (Exhaust Gas Recycle Procedure) -- 40 CFR 51 Appendix M.

(a) EPA Method 201A -- Determination of PM_{10} Emissions (Constant Sampling Rate Procedure) -- 40 CFR 51 Appendix M.

(42) EPA Method 202 -- Determination of Condensible Particulate Emissions from Stationary Sources -- 40 CFR 51 Appendix M.

(43) EPA Method 301 -- Field Data Validation Protocol -- 40 CFR Part 63, Appendix A.

(44) EPA Method 303 -- Coke Oven Door Emissions -- 40 CFR Part 63, Appendix A.
Specific Authority 403.061 FS.
Law Implemented 403.021, 403.031, 403.061, 403.087 FS.
History Formerly 17-2.700(6)(b), Amended 10-14-92, 6-29-93; Formerly 17-297.401; Amended 11-23-94, 1-1-96, 3-13-96, 10-7-96.

62-297.411 DEP Method 1. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)1, Formerly 17-297.411, Amended 11-23-94, Repealed 1-1-96.

62-297.412 DEP Method 2 (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)2, Formerly 17-297.412, Repealed 1-1-96.

62-297.413 DEP Method 3. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)3, Formerly 17-297.413, Repealed 1-1-96.

62-297.414 DEP Method 4. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)4, Formerly 17-297.414, Repealed 1-1-96.

62-297.415 DEP Method 5. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.a, Formerly 17-297.415; Amended 11-23-94, Repealed 1-1-96.

62-297.416 DEP Method 5A. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.b, Formerly 17-297.416, Repealed 1-1-96.

62-297.417 DEP Method 6. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)6, Formerly 17-297.417, Amended 11-23-94, Repealed 1-1-96.

62-297.418 DEP Method 7. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)7, Formerly 17-297.418, Repealed 1-1-96.

62-297.419 DEP Method 8. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)8, Formerly 17-297.419, Repealed 1-1-96.

62-297.420 DEP Method 9. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)9, Formerly 17-297.420, Amended 11-23-94, Repealed 3-13-96.

62-297.421 DEP Method 10. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)10, Formerly 17-297.421, Repealed 1-1-96.

62-297.422 DEP Method 11. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 62-2.700(6)(a)11, Formerly 17-297.422, Repealed 1-1-96.

62-297.423 EPA Method 12. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)12, Formerly 17-297.423, Amended 11-23-94, 1-1-96.

62-297.424 DEP Method 13. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)13, Formerly 17-297.424, Repealed 1-1-96.

62-297.440 Supplementary Test Procedures.
The following test procedures are adopted by reference. Copies of these documents are available from the emissions units set forth below. Copies may also be inspected at the Department's Tallahassee Office.

(1) ASTM Methods. Standard Methods published by the American Society for Testing and Materials are available from the Society at 1916 Race Street, Philadelphia, Pennsylvania 19103.

(a) ASTM D 322-67, 1972. Standard Method of Test for Dilution of Gasoline Engine Crankcase Oils.

(b) ASTM D 396-76. Standard Specification for Fuel Oils, superceding ASTM D 396-69.

(c) ASTM D 2880-76. Standard Specification for Gas Turbine Fuel Oils, superceding ASTM D 2880-71.

(d) ASTM D 975-77. Standard Specification for Diesel Fuel Oils, superceding ASTM D 975-68.

(e) ASTM D 323-72. Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method).

(f) ASTM D 97-66. Standard Test Method for Pour Point of Petroleum Oils.

(g) ASTM D 4057-88. Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(h) ASTM D 129-91. Standard Test Method for Sulfur in Petroleum Products (General Bomb Method).

(i) ASTM D 2622-94. Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry.

(j) ASTM D 4294-90. Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy.

(2) EPA Reports -- EPA occasionally publishes test methods and emission control guidelines in a report format. These documents are available (unless otherwise stated) from the National Technical Information Services, 5286 Port Royal Road, Springfield, Virginia 22216, and may be inspected at the Department's Tallahassee Office.

(a) Petroleum Liquid Storage.

1. Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, EPA 450/2-78-047, p. 5-3.

2. Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed- Roof Tanks, EPA 450/2-77-036, p. 6-2.

(b) Gasoline Bulk Terminals.

1. Vapor Control System Test.

a. VOC emissions from the vapor control system shall be determined by the method given in Appendix A of EPA 450/2-77-026, except that an adequate sampling time shall be at least six (6) hours of operation. For continuous vapor processing systems at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test. For intermittent vapor processing systems, at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test and at least two full cycles of operation of the vapor processing system shall occur. This test shall be performed prior to the date of compliance and annually thereafter. Test results records shall be maintained at the terminal until the subsequent annual test shall be made available to the Department upon request.

b. Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals, EPA 450/2-77-026, Appendix A. Emission Test Procedure for Tank Truck Gasoline Loading Terminals.

2. Vapor Leak Detection.

a. During loading or unloading operations at bulk terminals, there shall be no reading greater than or equal to 100 percent of the lower explosive level (LEL), measured as propane at 1 in. (2.5 centimeters) around the perimeter of a potential leak source as detected by a combustible gas detector using the procedure described in Appendix B of EPA 450/2-78-051.

b. Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems, EPA 450/2-78-051, Appendix B, Gasoline Vapor Leak Detection Procedures by Combustible Gas Detector.

(c) Gasoline Service Stations.

1. Design Criteria for Stage I Vapor Control: Gasoline Service Stations, USEPA, OAQPS, ESED, November, 1975.

2. [Reserved]

(d) Non-destructive Control Devices.

1. Measurement of Volatile Organic Compounds, EPA 450/2-78-041, Attachment 3, Alternate Test for Direct Measurement of Total Gaseous Organic Compounds Using a Flame Ionization Analyzer.

2. [Reserved]

(e) Perchloroethylene Dry Cleaning Systems.

1. Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems, EPA 450/2-78-050, p. 6-3, Compliance Procedures, Liquid Leakage.

2. RACT Compliance Guidance for Carbon Absorbers on Perchloroethylene Dry Cleaners. Task No. 119, Contract No. 68-01-4147. EPA, DSSE, May, 1980, pp. 8-21, Appendices A and B.

(f) Cross Recovery Determination. When determining if a kraft recovery furnace is a straight kraft or cross recovery furnace the procedure in 40 CFR 60.285(d)(3) of Subpart BB shall be used.

(3) American Conference of Governmental Industrial Hygienists, Recommended Practices -- Industrial Ventilation: A Manual of Recommended Practice. Equipment Specifications published in the 16th Edition of the Industrial Ventilation Manual (or any subsequent versions approved by the Department) are available from the American Conference of Governmental Industrial Hygienists, Committee on Industrial Ventilation, P. O. Box 16153, Lansing, Michigan 48901, and may be inspected at the Department's Tallahassee Office.

(4) American Petroleum Institute (API) Recommended Practices -- These are available from the API, 2101 L Street, Northwest, Washington, D. C. 20037

(a) API Standard 650, Welded Steel Tanks for Oil Storage, Sixth Edition, Revision 1, May 15, 1978.

(b) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February, 1980.

(c) API 1004, Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles, Fourth Edition, September 1, 1977.

(5) Technical Association of the Pulp and Paper Industry (TAPPI), Test Methods -- These are available from TAPPI, P. O. Box 105113, Atlanta, Georgia 30348.

(a) TAPPI Method T.624, Analysis of Soda and Sulfate White and Green Liquors.

(b) (Reserved).

(6) Sulphur Development Institute of Canada (SUDIC) Sampling and Testing Sulphur Forms -- These are available from SUDIC, Box 950, Bow Valley Square 1, 830, 202-6 Avenue S. W., Calgary, Alberta T2P 2W6.

(a) S1-77. Collection of a Gross Sample of Sulphur.

(b) S2-77. Sieve Analysis of Sulphur Forms, except paragraph 4.3 concerning wet sieving is not adopted.

(c) S3-77. Determination of Material Finer than No. 50 (300um) Sieve in Sulphur Forms by Washing.

(d) S5-77. Determination of Friability of Sulfur Forms.

(7) EPA VOC Capture Efficiency Test Procedures. Adopted by reference is an EPA memo dated April 16, 1990 entitled, "Guidelines for Developing a State Protocol for the Measurement of Capture Efficiency." A copy can be obtained by writing to: Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(a) Procedure F.1 -- Fugitive VOC Emissions from Temporary Enclosures.

(b) Procedure F.2 -- Fugitive VOC Emissions from Building Enclosures.

(c) Procedure G.1 -- Captured VOC Emissions.

(d) Procedure G.2 -- Captured VOC Emissions (dilution technique).

(e) Procedure L -- VOC in Liquid Input Stream.

(f) Procedure T -- Criteria for and Verification of Permanent or Temporary Total Enclosure.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(c); Amended 6-29-93, Formerly 17-297.440, Amended 11-23-94, 1-1-96.

62-297.450 EPA VOC Capture Efficiency Test Procedures.

(1) Applicability. The requirements set forth in Rules 62-297.450(2) and (3), F.A.C., shall apply to all regulated VOC emitting emissions units employing a control system pursuant to Rules 62-296.501 through 62-296.516, F.A.C., and Rule 62-296.800, F.A.C., except as provided in Rules 62-297.450(1)(a) and (b), F.A.C.

(a) If an owner or operator installs a Permanent Total Enclosure that meets the specifications of Procedure T, and which directs all VOC to a control device, the capture efficiency is assumed to be 100 percent, and the facility owner or operator is exempted from the requirements described in Rule 62-297.450(2) , F.A.C. This does not exempt the owner or operator from conducting any required control device efficiency test.

(b) If the owner or operator of an affected activity, process, or emissions unit uses a nondestructive control device designed to collect and recover VOC (e.g. carbon adsorber), an explicit measurement of capture efficiency is not necessary if the owner or operator is able to equate solvent usage with solvent recovery on a 24-hour (daily) basis, rather than a 30-day weighted average, and can determine this within 72 hours following each 24-hour period, and one of the following two criteria is also met:

1. The solvent recovery system (i.e., capture and control system) is dedicated to a single activity, process line, or emissions unit (e.g., one process line venting to a carbon adsorber system), or

2. The solvent recovery system controls multiple activities, process lines, or emissions units and the owner or operator is able to demonstrate that the overall control (i.e., the total recovered solvent VOC divided by the sum of liquid VOC input to all activities, process lines, or emissions units venting of the control system) meets or exceeds the most stringent emission standard applicable for any activity, process line, or emissions unit venting to the control system.

(c) If the conditions given above in Rule 62-297.450(1)(b), F.A.C., are met, the overall emission reduction efficiency of the system can be determined by dividing the recovered liquid VOC by the input liquid VOC. The general procedure for this determination is given in 40 CFR 60.433, which is adopted by reference.

(2) Specific Requirements. The capture efficiency of a capture system shall be determined using one of the following EPA procedures, or an alternate capture efficiency test procedure if approved by the Department under the provisions of Rule 62-297.620, F.A.C.

(a) Gas/gas method using a Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = Gw/(Gw + Fw)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)

Gw = mass of VOC captured and delivered to control device using a Temporary Total Enclosure

Fw = mass of fugitive VOC that escapes from a Temporary Total Enclosure Procedure G.1 or Procedure G.2 is used to obtain Gw. Procedure F.1 is used to obtain Fw.

(b) Liquid/gas method using Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F = mass of fugitive VOC that escapes from a Temporary Total Enclosure Procedure L is used to obtain L. Procedure F.1 is used to obtain F.

(c) Gas/gas method using the building or room in which the affected activity, process, or emissions unit is located as the enclosure and in which G and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room must be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

CE = G/(G + F sub B)

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
G = mass of VOC captured and delivered to a control device
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure G.1 or Procedure G.2 is used to obtain G. Procedure F.2 is used to obtain F_B.

(d) Liquid/gas method using the building or room in which the affected activity, process, or emissions unit located as the enclosure and in which L and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room shall be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F_B)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure L is used to obtain L. Procedure F.2 is used to obtain F sub B.

(3) Sampling Requirements. A capture efficiency test shall consist of at least three sampling runs. Each run shall cover at least one complete production cycle, but shall be at least 3 hours long. The sampling time for each run need not exceed 8 hours, even if the production cycle has not been completed.

(4) Recordkeeping and Reporting.

(a) The owner or operator of an affected activity, process, or emissions unit shall submit to the Department a list of the procedures that will be used for the capture efficiency tests at the owner or operator's facility. A copy of the list shall be kept on file at the affected facility.

(b) Required test reports shall be submitted to the Department within forty-five (45) days of the test date. A copy of the results shall be kept on file at the facility.

(c) If any physical or operational change is made to a control system, the owner or operator of the affected facility shall notify the Department of the change within ten (10) working days after making such change. The Department shall require the owner or operator of the affected activity, process, or emissions unit to conduct a new capture efficiency test if the Department has reason to believe (based on engineering calculations or empirical evidence) that a physical or operational change made to the capture system has decreased the overall emissions reduction efficiency of the system.

(d) Notwithstanding the provisions of Rule 62-297.340(1), F.A.C., the owner or operator of an affected activity, process, or emissions unit shall notify the Department thirty (30) days prior to performing any capture efficiency and/or control efficiency tests.

(e) The owner or operator of an affected activity, process, or emissions unit using a Permanent Total Enclosure shall demonstrate that this enclosure meets the requirement given in Procedure T for a Permanent Total Enclosure during any required control device efficiency test.

(f) The owner or operator of an affected activity, process, or emissions unit using a Temporary Total Enclosure shall demonstrate that this enclosure meets the requirements given in Procedure T for a Temporary Total Enclosure during any required control device efficiency test.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(7); Amended 6-29-93, Formerly 17-297.450, Amended 11-23-94, 1-1-96.

62-297.500 Continuous Emission Monitoring Requirements. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92; 6-29-93; Formerly 17-297.500; Repealed 11-23-94.

62-297.520 EPA Continuous Monitor Performance Specifications.

This rule adopts the continuous monitor performance specifications to be used where required by Department air pollution rule or air permit. The EPA performance specifications listed in this rule and contained in 40 CFR 60, Appendix B, are adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 3--Specifications and Test Procedures for O_2 and CO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(4) Performance Specification 4--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(5) Performance Specification 4A--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(6) Performance Specification 5--Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources.

(7) Performance Specification 6--Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources.

(8) Performance Specification 7--Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: New 6-29-93, Formerly 17-297.520, Amended 11-23-94, 3-13-96.

62-297.570 Test Reports. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(8), Formerly 17-297.570, Amended 11-23-94, Repealed 3-13-96.

62-297.620 Exceptions and Approval of Alternate Procedures and Requirements.

(1) The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

(2) The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

(3) The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.

(4) In the case of an emissions unit which has the potential to emit less than 100 tons per year of particulate matter and is equipped with a baghouse, the Secretary or the appropriate Director of District Management may waive any particulate matter compliance test requirements for such emissions unit specified in any otherwise applicable rule, and specify an alternative standard of 5% opacity. The waiver of compliance test requirements for a particulate emissions unit equipped with a baghouse, and the substitution of the visible emissions standard, shall be specified in the permit issued to the emissions unit.

If the Department has reason to believe that the particulate weight emission standard applicable to such an emissions unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(3); Amended 6-29-93; Formerly 17-297.620; Amended 11-23-94.

Attachment L

Attachment L

Compliance Test Report

Compliance Test Report

A compliance test report will be included with the operating permit application after construction and initial testing has been completed.

Attachment M

Attachment M

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

After a normal start up is initiated, the time is documented when the turbine starts firing. The turbine then continues with a normal start up and warm up. Time is documented again when the breaker closes. Upon the generator reaching 60 MW, the water injection pump is turned on (fuel oil only), and flow is established to the turbine. When the NO_x emissions are controlled and stable, the time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to 60 MW and the water injection pumps are taken out of service (fuel oil only-this time is documented). Time is again recorded when the turbine stops firing.

Attachment N

Attachment N

Operation and Maintenance Plan

Operation and Maintenance Plan

An operation and maintenance plan will be submitted if required by the construction permit.

Attachment O

Attachment O

Unit Specific Applicable Requirements

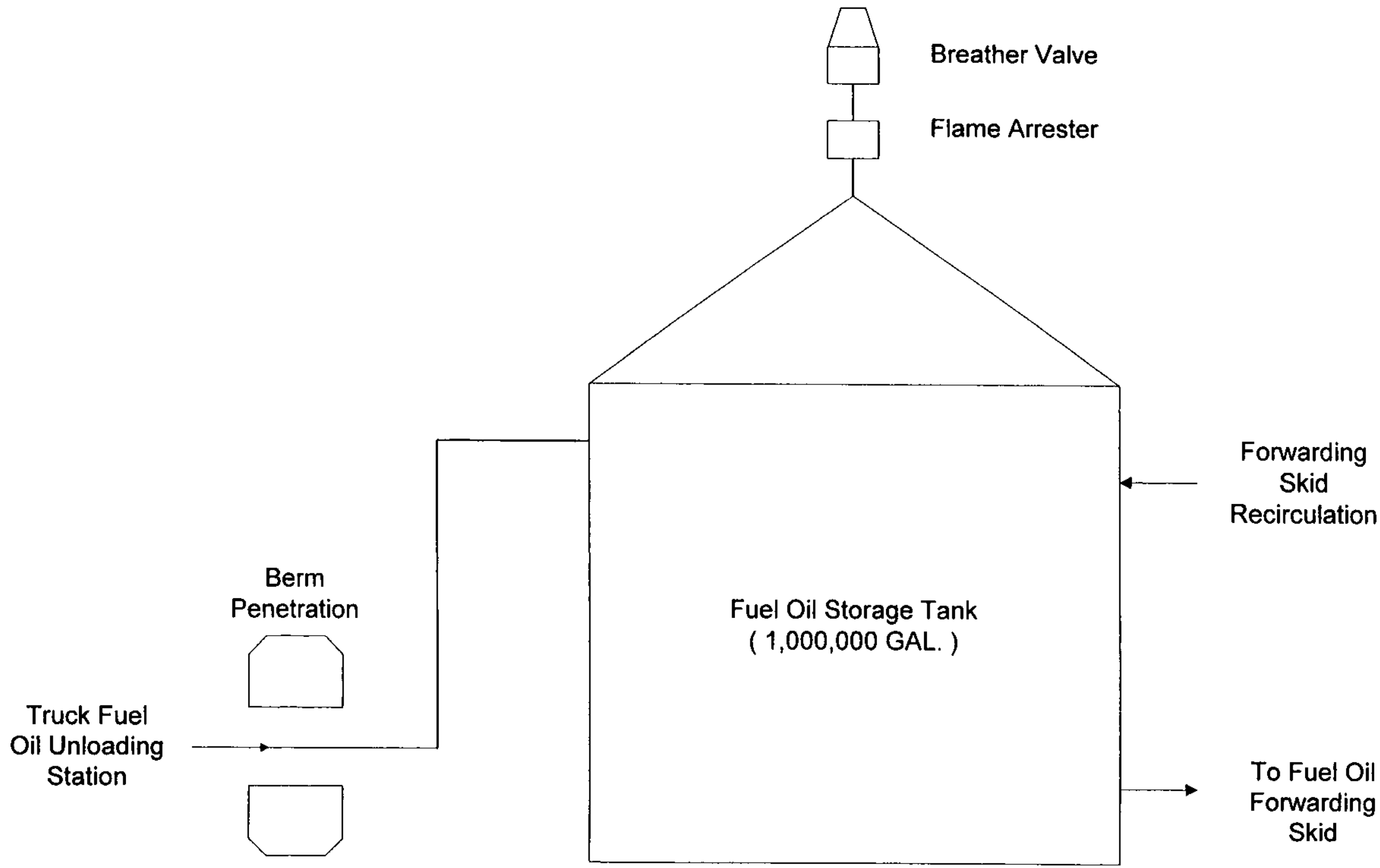
1,000,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 19984.
40 CFR 60.116b, Monitoring of Operations	The owner or operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b) for a period of at least two (2) years.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of Excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.

Attachment P

Attachment P

Process Flow Diagram



Breather Valve
Flame Arrester
Forwarding Skid Recirculation
Berm Penetration
Fuel Oil Storage Tank (1,000,000 GAL.)
Truck Fuel Oil Unloading Station
To Fuel Oil Forwarding Skid

Attachment Q

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification	
Identification No.:	
City:	Brandy Branch
State:	FL
Company:	JEA - F.O. Storage Tanks
Type of Tank:	Vertical Fixed Roof
Description:	Fuel Oil Storage Tank
Tank Dimensions	
Shell Height (ft):	40.0
Diameter (ft):	65.6
Liquid Height (ft):	39.8
Avg. Liquid Height (ft):	20.0
Volume (gallons):	1000000
Turnovers:	11.1
Net Throughput (gal/yr):	11100000
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	56.00
Slope (ft/ft) (Cone Roof):	0.0000
Breather Vent Settings	
Vacuum Setting (psig):	-0.03
Pressure Setting (psig):	0.03

Meteorological Data Used in Emission Calculations: Jacksonville, Florida (Avg Atmospheric Pressure = 14.7 psia)

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
LIQUID CONTENTS OF STORAGE TANK

Basis for Vapor Pressure Mixture/Component Calculations	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight
Distillate fuel oil no. 2 Option 3: A=12.1010, B=8907.0	All	69.94	64.36	75.52	68.02	0.0089	0.0075	0.0107	130.000			188.00

Annual Emission Calculations

Standing Losses (lb):	243.2499
Vapor Space Volume (cu ft):	86154.41
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.038277
Vented Vapor Saturation Factor:	0.988064
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	86154.41
Tank Diameter (ft):	65.6
Vapor Space Outage (ft):	25.49
Tank Shell Height (ft):	40.0
Average Liquid Height (ft):	20.0
Roof Outage (ft):	5.49
Roof Outage (Dome Roof)	
Roof Outage (ft):	5.49
Dome Radius (ft):	56
Shell Radius (ft):	32.8
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Daily Avg. Liquid Surface Temp.(deg. R):	529.61
Daily Average Ambient Temp. (deg. R):	527.67
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	527.69
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqft□day):	1438.00

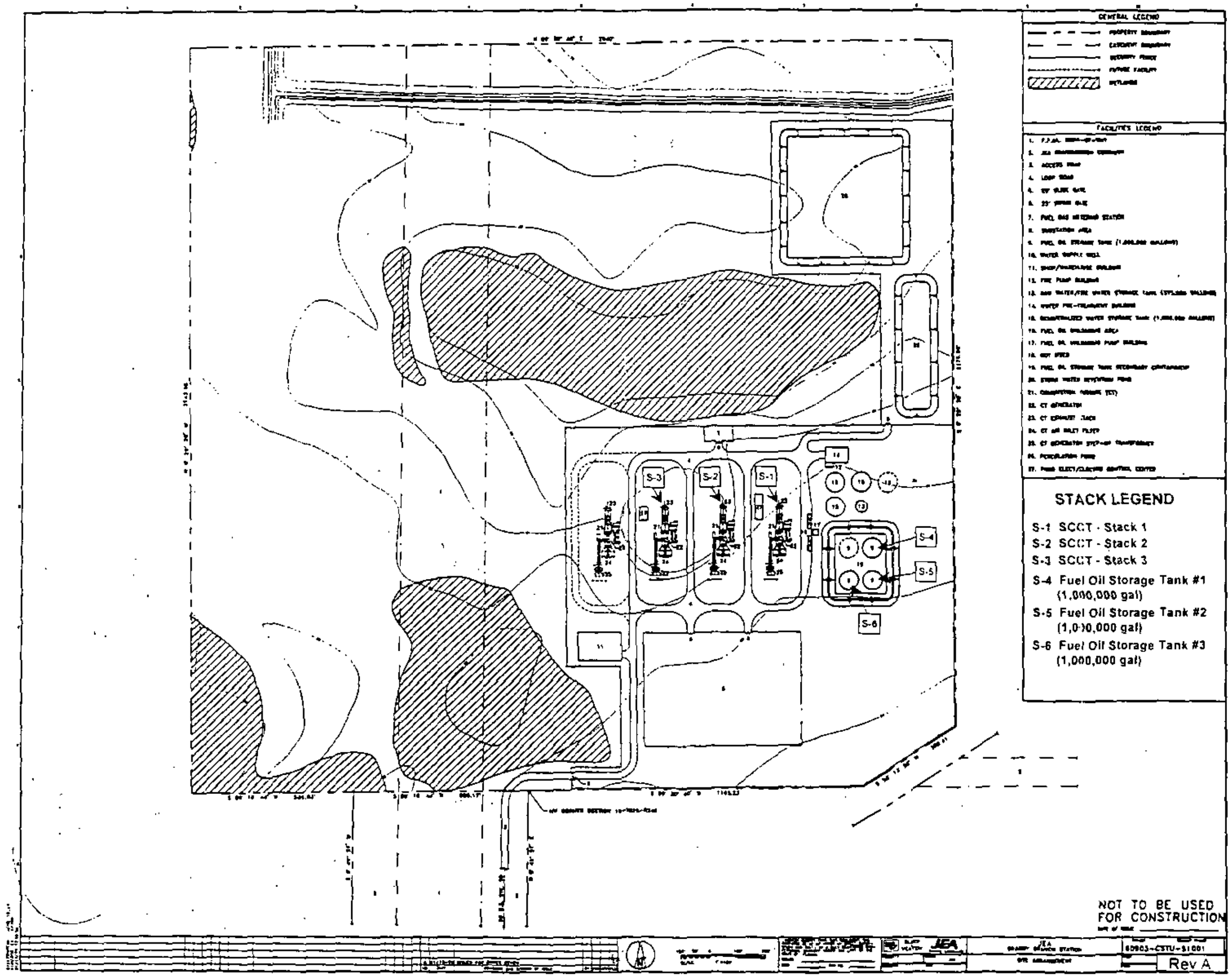
Vapor Space Expansion Factor

Vapor Space Expansion Factor:	0.038277
Daily Vapor Temperature Range (deg.R):	22.32
Daily Vapor Pressure Range (psia):	0.003180
Breather Vent Press. Setting Range(psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.007476
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.010655
Daily Avg. Liquid Surface Temp. (deg R):	529.61
Daily Min. Liquid Surface Temp. (deg R):	524.03
Daily Max. Liquid Surface Temp. (deg R):	535.19
Daily Ambient Temp. Range (deg.R):	21.50

Annual Emission Calculations	
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.988064
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Space Outage (ft):	25.49
Working Losses (lb):	307.2093
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Annual Net Throughput (gal/yr):	11100000
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	134518
Maximum Liquid Height (ft):	39.8
Tank Diameter (ft):	65.6
Working Loss Product Factor:	1.00
Total Losses (lb):	550.46

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Working	Total
Distillate fuel oil no. 2	243.25	307.21	550.46
Total:	243.25	307.21	550.46



JEASTACK.SRF

JEA 60903.0030
Jacksonville, Florida
Enveloped Stack Parameters

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 03/22/99 02 11 PM

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	100 Percent							100 Percent								
Turbine	PG7241 (FA)			Representative*		59 Degrees		PG7241 (FA)			Representative*		59 Degrees			
Ambient Temperature (F)	95	59	--	100 Pecent Load		100 Pecent Load		95	59	20	100 Pecent Load		100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	147.76	156.75	164.0	147.76 ft/s	45.04 m/s	156.75 ft/s	47.78 ft/s	151.8	161.6	168.04	151.8 ft/s	46.27 m/s	161.80 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1144	1116	1081	1081 F	855.93 K	1116.00 F	875.37 K	1133	1098	1068	1068 F	848.71 K	1098.00 F	865.37 K	1116.00 F	875.37 K
Emissions (lb/h)																
NOx (f)	71.20	79.20	84.80	84.8 lb/h	10.68 g/s	36.16 lb/h	4.56 g/s	266.00	318.00	338.00	338 lb/h	42.59 g/s	29.04 lb/h	3.66 g/s	65.21 lb/h	8.22 g/s
CO	43.00	48.00	52.00	52 lb/h	6.55 g/s	21.82 lb/h	2.76 g/s	59.00	65.00	69.00	69 lb/h	8.69 g/s	5.94 lb/h	0.75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	0.97	1.07	1.14	1.14 lb/h	0.14 g/s	0.49 lb/h	0.06 g/s	88.38	98.21	104.30	104.3 lb/h	13.14 g/s	8.97 lb/h	1.13 g/s	9.46 lb/h	1.19 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.60	2.80	3.00	3 lb/h	0.38 g/s	1.28 lb/h	0.16 g/s	2.60	3.00	3.00	3 lb/h	0.38 g/s	0.27 lb/h	0.03 g/s	1.55 lb/h	0.20 g/s

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	75 Percent							75 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees		PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load		95	59	20	75 Pecent Load		75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	124.17	129.71	133.13	124.17 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s	126.43	131.67	135.15	126.43 ft/s	38.54 m/s	131.67 ft/s	40.13 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873.15 K	1139.00 F	888.15 K	1200	1194	1183	1183 F	912.59 K	1194.00 F	918.71 K	1139.00 F	888.15 K
Emissions (lb/h)																
NOx (f)	58.40	63.20	67.20	67.2 lb/h	8.47 g/s	28.86 lb/h	3.64 g/s	232.00	256.00	271.00	271 lb/h	34.14 g/s	23.38 lb/h	2.95 g/s	52.24 lb/h	6.58 g/s
CO	36.00	39.00	41.00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s	47.00	50.00	51.00	51 lb/h	6.43 g/s	4.57 lb/h	0.58 g/s	22.37 lb/h	2.82 g/s
SO2 (a)	0.79	0.86	0.92	0.92 lb/h	0.12 g/s	0.39 lb/h	0.05 g/s	72.32	79.69	84.44	84.44 lb/h	10.64 g/s	7.28 lb/h	0.92 g/s	7.67 lb/h	0.97 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	1.00 lb/h	0.13 g/s	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	0.20 lb/h	0.03 g/s	1.21 lb/h	0.15 g/s

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	50 Percent							50 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees		PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load		95	59	20	50 Pecent Load		50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	106.35	110.53	112.68	106.35 ft/s	32.42 m/s	110.53 ft/s	33.69 m/s	108.45	112.04	113.42	108.45 ft/s	33.06 m/s	112.04 ft/s	34.15 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1184	1160	1160 F	899.82 K	1184.00 F	913.15 K	1200	1200	1200	1200 F	922.04 K	1200.00 F	922.04 K	1184.00 F	913.15 K
Emissions (lb/h)																
NOx (f)	46.40	50.40	52.80	52.8 lb/h	6.65 g/s	23.01 lb/h	2.90 g/s	182.00	199.00	209.00	209 lb/h	26.33 g/s	18.17 lb/h	2.29 g/s	41.19 lb/h	5.19 g/s
CO	30.00	33.00	34.00	34 lb/h	4.28 g/s	15.07 lb/h	1.90 g/s	74.00	63.00	57.00	74 lb/h	9.32 g/s	5.75 lb/h	0.72 g/s	20.82 lb/h	2.62 g/s
SO2 (a)	0.64	0.69	0.73	0.73 lb/h	0.09 g/s	0.32 lb/h	0.04 g/s	57.30	62.70	65.90	65.9 lb/h	8.30 g/s	5.73 lb/h	0.72 g/s	6.04 lb/h	0.76 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.82 lb/h	0.10 g/s	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.16 lb/h	0.02 g/s	0.99 lb/h	0.12 g/s

NOTE:

(a) SO2 values were calculated based on 0.2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23.8 ft^3)*(20.675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr.
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639.4 MBtu/hr)*(10^6 BTU/MBtu) = 88.38 lb/hr.

(b) PM emission values are for front half filterable emissions only.

(c) VOC emissions represent 20% of the UHC emissions.

(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.

(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.

(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.