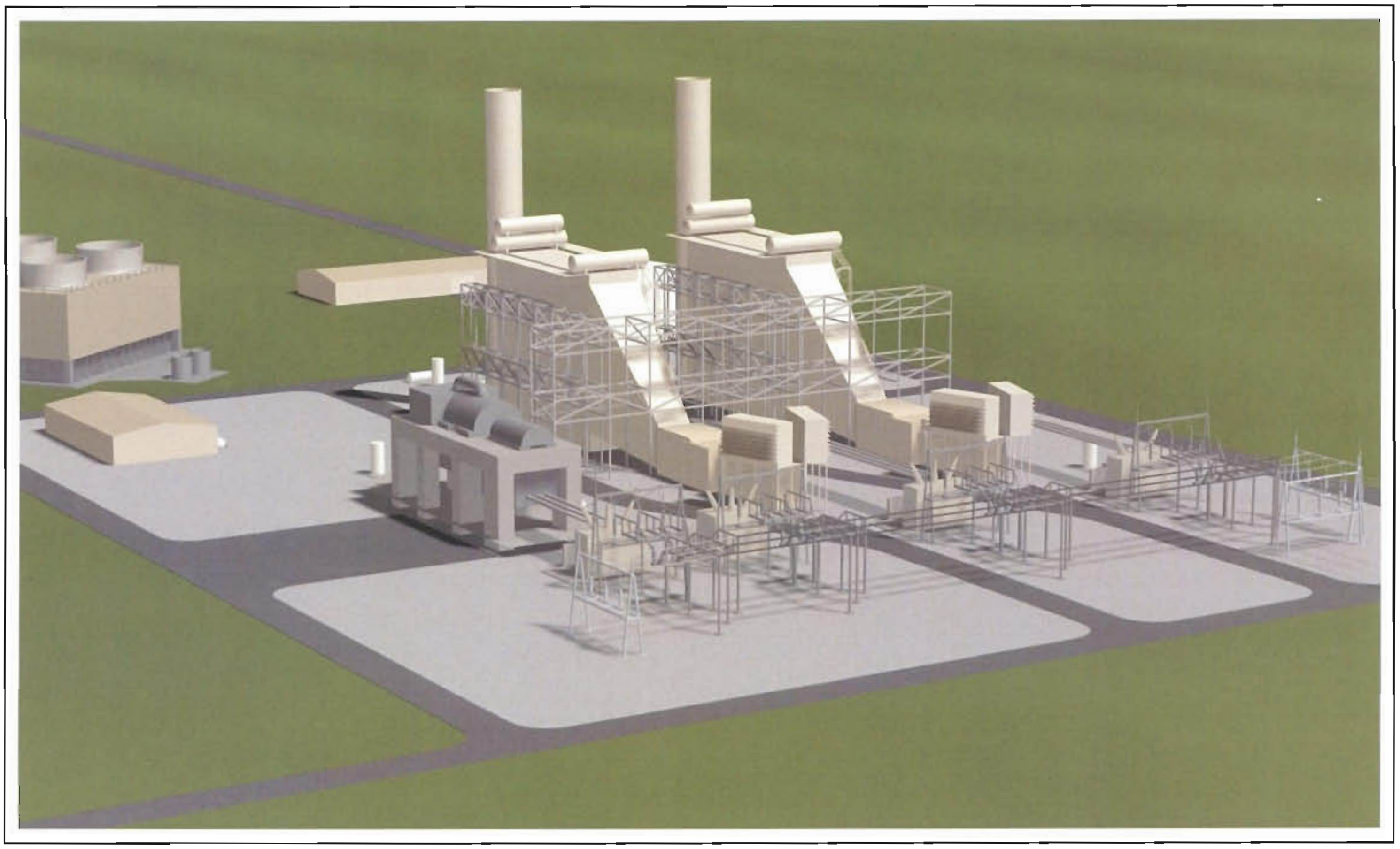
Supplemental Site Certification Application

Appendix 10.7 – PSD Application



Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A

B&V Project 98362 **January 2001**

FMPA KUA KISSIMMEE UTILITY AUTHORITY OUC The *Reliable* One SOUTHERN COMPANY *Energy to Serve Your World*

Appendix 10.7

Air Construction Application Forms for the Curtis H. Stanton Energy Center Combined Cycle Combustion Turbine Project

Ready 2 RUN

Submitted by

Orlando Utilities Commission
Kissimmee Utility Authority
Florida Municipal Power Authority
and
Southern Company-Florida, LLC

Prepared by
Black & Veatch

January 2001
Project No. 98362

0950137-002-AC
PSD-FL-313
Date of Application: 1/22/01

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1.0 Introduction

Orlando Utilities Commission (OUC), in conjunction with Kissimmee Utility Authority (KUA), Florida Municipal Power Authority (FMPA), and Southern-Florida, propose to construct and operate a 633 MW (nominal) electric generating unit at the existing Curtis H. Stanton Energy Center facility (hereinafter referred to as the "Project") near the city of Orlando, Florida in Orange County.

The Project will include the construction of two combined cycle combustion turbine (CCCT) units nominally rated at approximately 317 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a backup fuel. Each CCCT will be equipped with a heat recovery steam generator (HRSG) containing natural gas-fired duct burners. The two CCCT/HRSGs will feed a single, common steam turbine generator, this configuration is regularly referred to as a 2x1 configuration.

This report is a technical support document for the Prevention of Significant Deterioration (PSD) 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, 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 east central Orange County, Florida. Figure 2-1 shows the general location of the Project, which is approximately 8 miles east of the city of Orlando. The approximate Universal Transverse Mercator (UTM) coordinates of the Project are 483,609 m East and 3,151,100 m North. The nearest Federal PSD Class I Area is the Chassahowitzka National Wildlife Refuge located approximately 140 kilometers (km) west-northwest of the Project.

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

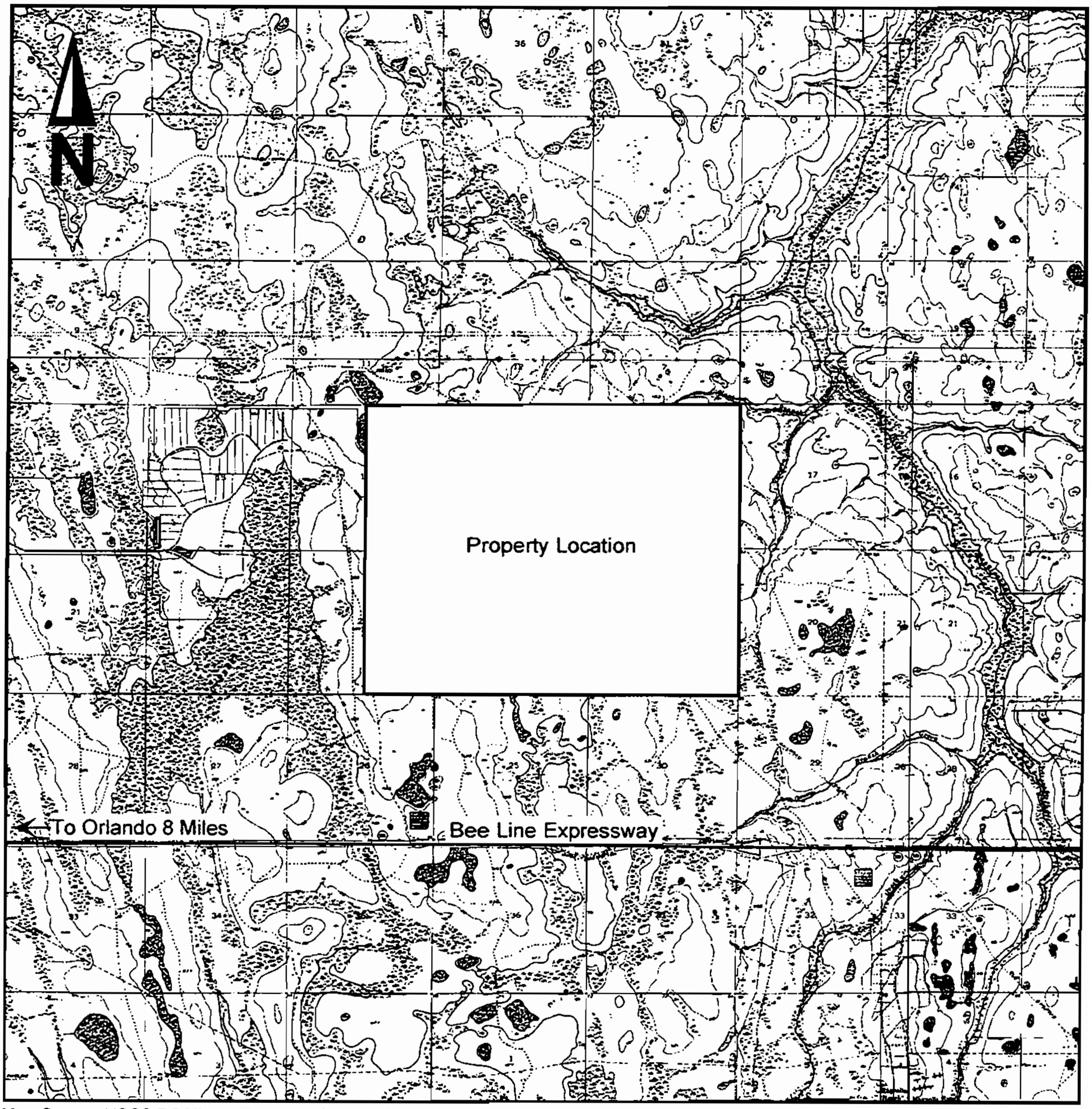
2.2 Project Description

The Project will be located at the existing Stanton Energy Center. The two CCCT units will be operated in a 2x1 configuration. Major equipment associated with each CCCT unit will consist of a General Electric (Model PG7241FA) combustion turbine generator, heat recovery steam generator (HRSG) with supplemental duct firing, steam generator, a 10-cell cooling tower, and a No. distillate fuel oil storage tank.

The project operation will consist of two CCCT/HRSGs capable of operating 8,760 hours while firing natural gas with the potential of 8,760 hours of natural gas duct firing and 1,000 hours of power augmentation, plus 1,000 hours of distillate fuel oil firing, as backup, per CCCT.

The CCCT/HRSG will use evaporative coolers as necessary to cool the compressor inlet air prior to its combining with fuel in the combustor of the CCCT. The thermal energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as these gases expand through the turbine sections of the CCCTs. The rotating mechanical energy will be converted into electrical energy via a shaft on the CCCT connected to an electrical generator. The remaining usable thermal energy in the combustion gases will be exchanged with water/steam in the HRSG.

Supplemental (duct) firing with natural gas will be used to increase the thermal energy of the combustion gases exhausting from each CCCT. The resulting high-pressure steam produced in each HRSG will be expanded through a single steam turbine. The rotating mechanical energy generated by the steam turbine will be converted into



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Miles

0 1 2 3

Stanton Energy Center
Property Location

Figure 2-1

Site Location.srf

electrical energy via a shaft connected to an electrical generator. The exhaust gases will exit to the atmosphere after leaving the HRSG stack.

The CCCT/HRSG will also have the capability of augmenting of the power output by utilizing steam augmentation as the method used to increase power. Steam is injected into the combustor or combustor head end and increases overall mass flow into the CCCT/HRSG, and therefore, output. Steam injection can result in power increases of 15 to 18 percent by injection of up to 5 percent mass flow (of compressor inlet air) of steam into the compressor discharge.

A CCCT/HRSG operating matrix has been developed and is included in Attachment 1. A site arrangement showing the various emission units and structures/buildings at the Project is presented in Figure 2-2.

2.3 Project Emissions

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

- Two General Electric CCCT/HRSGs with supplemental firing.
- One, 10-cell linear mechanical draft cooling tower.
- One, No. 2 distillate fuel oil storage tank (approximately 1,680,000 gallons)

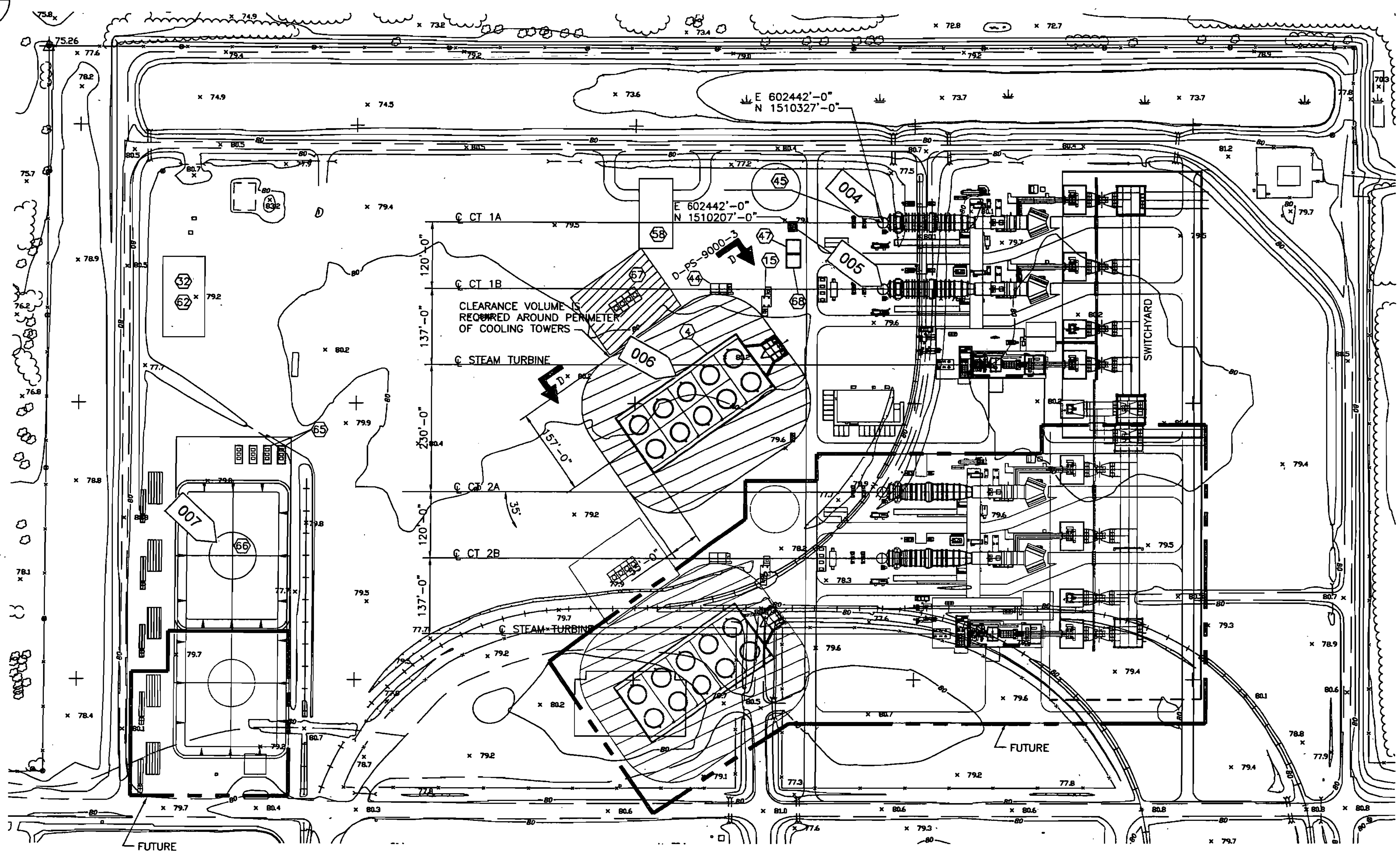
2.3.1 Project Emissions

Performance data for the CCCT/HRSG, based on vendor data from GE at design loads of 50, 75, and 100 percent, natural gas and distillate fuel oil firing, and ambient air temperatures of 19, 45, 60, 70, and 95° F, are provided in Attachment 2.

Ambient temperature data was selected based on meteorological data from Orlando, Florida. An ambient temperature of 19° F represents the lowest anticipated site temperature and maximum power generation. An ambient temperature of 70° F represents the average annual site temperature which is representative of the average heat input rate. An ambient temperature of 95° F represents the highest anticipated site temperature which corresponds to the lowest heat input rate for the combustion turbine and results in the maximum required duct firing and evaporative cooling rates to maintain the desired plant electrical output.

The maximum pound per hour emission rates for all loads and temperatures for combined cycle operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

D-PS-9000-1



NOTES:

NEW STACK COORDINATES BASED ON NAD83 FLORIDA STATE PLANES, EASTERN ZONE, U.S. FOOT:

CENTER UNIT 1A HRSG STACK:	E 602442'-0" N 1510327'-0"
CENTER UNIT 1B HRSG STACK:	E 602442'-0" N 1510207'-0"
CENTER UNIT 2A HRSG STACK:	E 602442'-0" N 1509840'-0"
CENTER UNIT 2B HRSG STACK:	E 602442'-0" N 1509720'-0"

NEW STACK COORDINATES BASED ON NAD83 UTM, ZONE 16 NORTH, METER:

CENTER UNIT 1A HRSG STACK:	E 1071425.2056 N 3165216.3816
CENTER UNIT 1B HRSG STACK:	E 1071427.0434 N 3165179.7166
CENTER UNIT 2A HRSG STACK:	E 1071432.6637 N 3165067.5830
CENTER UNIT 2B HRSG STACK:	E 1071434.5014 N 3165030.9181

⬡ DENOTES EQUIP. NO. – SEE D-PS-9000-2 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=60'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=400'-0"

CAD 9000-1D.DWG
AutoCad SHW-14

PRELIMINARY

Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

REVISION	DATE	DESCRIPTION	BY
REVISION D	01/16/00	1. REVISED TITLE BLOCK	SHW
REVISION C	12/7/00	1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	DWR
REVISION B	10/24/00	1. ADDED SERVICE WATER COOLER 1. ADDED LOCATION OF FUTURE BLOCK.	SHW
REVISION A	9/22/00	ISSUED FOR REVIEW	SHW

DESIGNED	DRAWN	CHECKED	SCALE	PROJECT I.D.	DRAWING NUMBER	REV.
SHW	SHW		1"=200'-0"		D-PS-9000-1	D

2.4 Maximum Potential-to-Emit

The potential-to-emit (PTE) was estimated from the maximum hourly emission rate for each pollutant considering all ambient temperatures in combined cycle operation at 100 percent load. The PTE for each pollutant was based on specific scenarios within the performance data and calculated at 1,000 hours of power augmentation and duct firing using natural gas, 6,760 hours of duct firing using natural gas, and 1,000 hours of distillate fuel oil (0.05 percent sulfur) firing per CCCT. The PTE 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 PTE example calculations are 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 Project is in an attainment area with respect to all pollutants. As such, the PSD program will apply to the Project, as administered by the State of Florida under 62-212.400, FAC, 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 Stanton Energy Center's new Project is classified as a major modification, having a PTE greater than 100 tpy for at least one regulated pollutant. Additionally, the estimated emission increases of NO_x, CO, PM/PM_{10}, and SO_2, and VOC resulting from the modification exceed the PSD significant emissions levels of 40, 100, 25/15, 40, and 40 tpy, respectively. Therefore, the Project emissions of NO_x, CO, PM/PM_{10}, and SO_2, and VOC are subject to PSD review as a major modification. The

Table 2-1 **CTG/HRSG Maximum Emission Rates (lb/h)**[a]		
Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NO_x	30.38	79.69
CO	142.51	71.00
PM/PM_{10}	11.71	17.00
SO_2	3.50	107.00
VOC	20.13	8.00
H_2SO_4	0.43	13.05

[a]Maximum pound per hour emission rates considering all loads (100, 75, and 50%), all temperatures (19, 45, 60, 70, and 95°F), and fuels for combined cycle operation.

[b]H_2SO_4 emission rate based on a 10% conversion of SO_2 to SO_3 and a molecular ratio of 1.22 from SO_3 to H_2SO_4 (in the stack and SCR).

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO_x	314.5[a]	40	yes
CO	870.1[a]	100	yes
PM/PM_{10}	127.6[a,b,c]	25/15	yes
SO_2	134.1[a,d]	40	yes
VOC	105.8[a,e]	40	yes
H_2SO_4	17.6[a,f]	7	yes
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Total Fluorides	negl.	3	no
Lead	0.03[g]	0.6	no
Mercury	0.004[g]	0.1	no
Total HAPs	18.0[g,h]	10/25	no

[a]Based on maximum lb/h emission rate considering all temperature conditions for base load and assuming operating scenarios of 1,000 hours of power augmentation and duct firing on natural gas, 6,760 hours of duct firing on natural gas, and 1,000 hours of distillate fuel oil firing per CCCT.

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

[c]PM/PM_{10} PTE include emissions from the cooling tower.

[d]Based on 0.05% sulfur distillate fuel oil and 0.5 gr/100 scf sulfur natural gas.

[e]VOC PTE includes emissions from the fuel oil storage tank.

[f]H_2SO_4 emission rate based on a 10% conversion of SO_2 to SO_3 and a molecular ratio of 1.22 from SO_3 to H_2SO_4 for Natural Gas firing in addition to sulfur mist emissions presented in the performance data for Fuel Oil firing.

[g]Based on AP-42 emission factors, assuming a conservative worst-case operating scenario of two CCCT/HRSGs operating 8,760 hours firing natural gas with 8,760 hours of natural gas duct firing and 1,000 hours of power augmentation, plus 1,000 hours of distillate fuel oil firing per CCCT.

[h]HAPs calculation sheet is included Attachment 3.

Note: PTE example calculations are provided in Attachment 3.

PSD review includes a BACT analysis, air quality impact analysis, and an assessment of the Project's impact on general commercial and residential growth, soils and vegetation, and visibility, as well as a Class I impact analysis.

3.0 Best Available Control Technology

A summary of the best available control technology (BACT) analysis for the Project has been included below. Additionally, the detailed BACT for the Project has been included as Attachment 4.

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for the project. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for the BACT analysis are based on each CCCT/HRSG unit operating at three different operating conditions. These three conditions are 1) natural gas operation at full load with duct burner firing for 6,760 hours per year at and ambient temperature of 70°F, 2) natural gas firing with power augmentation for 1,000 hours per year at an ambient temperature of 70°F with the combustion turbine and duct burner firing at full load, 3) fuel oil firing of the combustion turbine-generator (CTG) unit at full load operation without duct firing for 1,000 hours per year at an ambient temperature of 70°F.

GE PG7241(FA) CCCT/HRSG Units:

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

Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O_2.

Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O_2.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O_2 (without power augmentation) and 26.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O_2 during fuel oil firing.

Particulate (PM/PM_{10}) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O_2

(without power augmentation) and 6.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O_2 during fuel oil firing.

Sulfur Dioxide (SO_2) emissions -- BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate (PM/PM_{10}) emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those PSD pollutants which will have a PTE greater than the PSD significant emission rate (i.e., NO_x, CO, PM/PM_{10}, and SO_2). 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 OUC in a letter from Black & Veatch dated June 7, 2000. The agreed upon protocol was a result of an earlier meeting with FDEP on May 31, 2000 in which details of the analysis to be performed were discussed and approved. A copy of the protocol is presented in Attachment 5.

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3, Version 00101) air dispersion model was used to predict maximum ground level concentrations associated with the Project. 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 determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing the Project's proposed operating load range (i.e., 50, 75, and 100 percent loads) with a representative set of stack parameters and pollutant emission rates to produce the worst-case plume dispersion conditions and highest model predicted concentrations (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as enveloping.

The representative stack parameters and emission rates for each load, fuel type, and operating scenario were provided by Southern Company on November 17, 2000 and 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 Project 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 Project 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

Existing (Coal Units 1 and 2) and proposed (CCCT/HRSG Unit 3) buildings and structures were analyzed to determine the 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, Version 95086) 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 the Project is 64.05 m (210 ft). The actual modeled height for each stack is 48.768 m (160 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[a]

CCCT/HRSG Operating Scenario	ISCST3 Source ID[b]	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO_x	CO	PM/PM_{10}	SO_2
Natural Gas	#STK16G	100	48.77	5.79	16.75	348.71	3.83	17.96	1.48	0.44
	#STK76G	75	48.77	5.79	13.49	347.59	2.42	5.04	1.13	0.35
	#STK56G	50	48.77	5.79	11.19	342.59	1.91	4.16	1.13	0.35
Distillate Fuel Oil	#STK16O	100	48.77	5.79	19.90	406.48	10.04	8.95	2.14	13.48
	#STK76O	75	48.77	5.79	16.94	400.93	8.01	7.43	2.14	10.84
	#STK56O	50	48.77	5.79	13.38	393.71	6.21	8.32	2.14	8.57
Annualized[c]	#STK16	100	48.77	5.79	16.75	348.71	4.52	N/A	1.54	1.93
	#STK76	75	48.77	5.79	13.49	347.59	3.06	N/A	1.25	1.55
	#STK56	50	48.77	5.79	11.19	342.59	2.40	N/A	1.25	1.29

[a]Representative stack parameters and emission rates were provided by Southern-Florida on November 17, 2000 and January 11, 2001, and are contained in Attachment 2 and summarized for ISCST3 modeling in Attachment 3.

[b]The " #STK" character in the ISCST3 Source ID name refers to either 1STK,or 2STK, which refer to stack 1 or stack 2; 1,7,or 5 refer to 100, 75, or 50 percent load; 6 refers to a 160 foot stack; and G or O refer to natural gas or distillate fuel oil fired.

[c]Annualized emission rates at 100% load are based on the maximum lb/h emission rate considering all temperature conditions and assuming operating scenarios of 1,000 hours of power augmentation and duct firing on natural gas, 6,760 hours of duct firing on natural gas, and 1,000 hours of distillate fuel oil firing per CCCT. The annualized emission rates at 75 and 50% loads are based on the maximum lb/h emission rate considering all temperature conditions and assuming operating scenarios of 7,760 hours of duct firing on natural gas, and 1,000 hours of distillate fuel oil firing per CCCT. Other annualized stack parameters were based on the natural gas firing and the specific load worst-case exit velocity and temperature.

4.2.5 Receptor Grid and Terrain Considerations

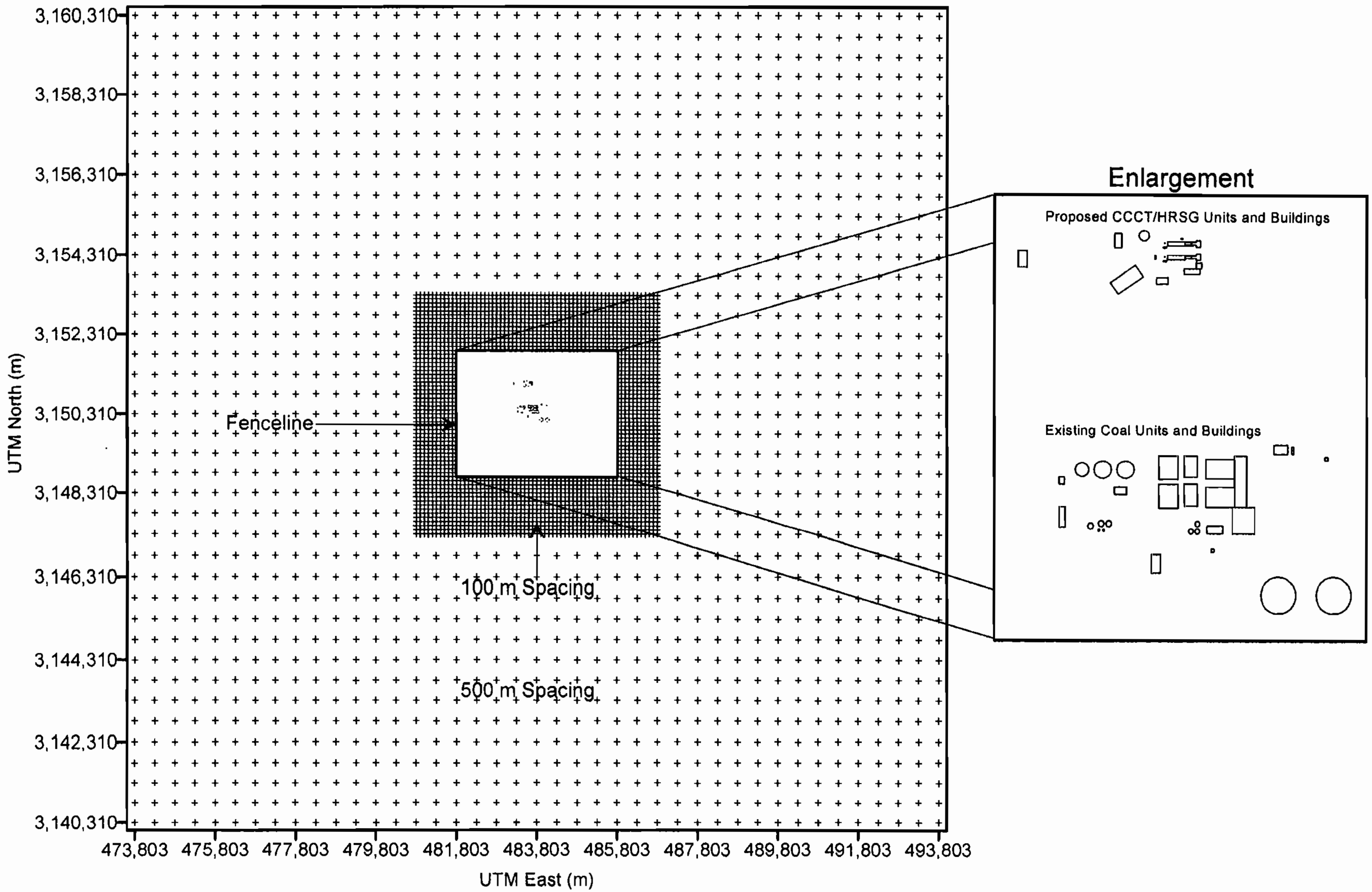
The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the Project was used. The rectangular grid network consists of 100 m spacing from the center of Stanton Energy Center out to 3 km, and then 500 m spacing from 3 to 10 km. Receptor spacing of 100 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors if the maximum predicted impacts occurred beyond the 100 m spacing. Figure 4-1 illustrates the nested rectangular grid, fenceline 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 (1987-1991) of surface and upper air meteorological data from Orlando, Florida and Tampa, Florida, 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, CO, PM/PM_{10}, and SO_2. 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, CO, PM/PM_{10}, and SO_2 for each applicable averaging period. The modeled sources for NO_x (annual), PM/PM_{10} (annual), and SO_2 (annual) included enveloped emissions over all loads and temperatures per fuel, and the final emission rate was calculated by combining these enveloped emissions to account for 1,000 hours per year firing distillate oil and 7,760 hours per year firing natural gas. Annual stack parameters were based on the worst-case, natural gas 100 percent load exit velocity and exit temperature. However, for CO (1-hour and 8-hour), PM/PM_{10} (24-hour), and SO_2 (3-hour and 24-hour), the modeled sources included enveloped emissions per load and per fuel.



Receptor Locations

Figure 4-1

RECEPTORS.SRF

Tables 4-2 through 4-9 present the results for the 5 year (1987-1991) modeling analysis for each pollutant and applicable averaging period. The underlined concentrations in each table represent the maximum modeled predicted impacts in each case. Electronic copies of the modeled files are contained in Attachment 6.

4.3.1 Comparison to PSD Significant Impact Levels and Preconstruction Monitoring Requirements

Table 4-10 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the preconstruction monitoring requirements. As Table 4-10 indicates, the Project's maximum predicted concentrations are less than the PSD Class II significant impact levels 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 preconstruction monitoring de minus levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD preconstruction monitoring requirements.

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

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m^3)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1987	0.09	480,302.5	3,149,310.0
CC7		75		0.08	481,002.5	3,149,710.0
CC5		50		0.09	481,602.5	3,150,010.0
CC1		100	1988	0.09	480,902.5	3,149,610.0
CC7		75		0.08	481,402.5	3,149,910.0
CC5		50		0.08	481,785.0	3,150,120.0
CC1		100	1989	0.10	483,702.5	3,153,310.0
CC7		75		0.08	483,702.5	3,153,210.0
CC5		50		0.09	483,702.5	3,152,910.0
CC1		100	1990	0.11	481,002.5	3,149,510.0
CC7		75		0.10	481,402.5	3,149,810.0
CC5		50		**0.11**	481,785.0	3,150,020.0
CC1		100	1991	0.11	483,602.5	3,153,310.0
CC7		75		0.09	483,602.5	3,153,210.0
CC5		50		0.10	483,602.5	3,152,910.0

*CC=Combined Cycle; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-3
ISCST3 Model Predicted Maximum 1-Hour Concentrations of CO

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
Natural Gas Firing						
CCNG1	1-Hour	100	1987	**55.91**	483,702.5	3,152,010.0
CCNG7		75		16.02	483,702.5	3,152,010.0
CCNG5		50		13.79	483,620.0	3,151,920.0
CCNG1		100	1988	39.22	483,902.5	3,152,110.0
CCNG7		75		14.76	484,202.5	3,152,610.0
CCNG5		50		14.05	484,402.5	3,152,510.0
CCNG1		100	1989	34.77	483,420.0	3,151,920.0
CCNG7		75		11.32	483,720.0	3,151,920.0
CCNG5		50		15.79	483,902.5	3,152,510.0
CCNG1		100	1990	42.55	484,502.5	3,153,110.0
CCNG7		75		12.12	484,502.5	3,153,110.0
CCNG5		50		11.68	484,302.5	3,152,610.0
CCNG1		100	1991	36.36	483,520.0	3,151,920.0
CCNG7		75		15.32	482,802.5	3,153,010.0
CCNG5		50		14.28	485,402.5	3,152,210.0
Fuel Oil Firing						
CCFO1	1-Hour	100	1987	11.34	483,902.5	3,152,210.0
CCFO7		75		9.96	483,902.5	3,152,110.0
CCFO5		50		13.04	482,802.5	3,154,310.0
CCFO1		100	1988	13.43	483,520.0	3,151,920.0
CCFO7		75		14.75	483,902.5	3,152,110.0
CCFO5		50		17.11	483,902.5	3,152,110.0
CCFO1		100	1989	11.78	485,102.5	3,152,410.0
CCFO7		75		9.89	485,102.5	3,152,410.0
CCFO5		50		14.08	485,420.0	3,151,920.0
CCFO1		100	1990	12.01	483,002.5	3,152,310.0
CCFO7		75		11.01	484,502.5	3,153,310.0
CCFO5		50		13.94	484,402.5	3,153,210.0
CCFO1		100	1991	11.57	484,520.0	3,151,920.0
CCFO7		75		11.47	482,502.5	3,153,310.0
CCFO5		50		15.51	483,320.0	3,151,920.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

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

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
Natural Gas Firing						
CCNG1	8-Hour	100	1987	12.77	483,802.5	3,152,110.0
CCNG7		75		4.41	485,820.0	3,150,300.0
CCNG5		50		4.82	485,820.0	3,150,300.0
CCNG1		100	1988	13.90	484,902.5	3,152,510.0
CCNG7		75		5.26	484,502.5	3,152,110.0
CCNG5		50		6.03	484,320.0	3,151,920.0
CCNG1		100	1989	14.11	481,302.5	3,150,810.0
CCNG7		75		4.92	481,702.5	3,150,910.0
CCNG5		50		5.22	484,402.5	3,152,110.0
CCNG1		100	1990	13.24	485,820.0	3,150,000.0
CCNG7		75		4.38	484,002.5	3,152,610.0
CCNG5		50		4.98	481,785.0	3,150,020.0
CCNG1		100	1991	**14.14**	483,602.5	3,152,910.0
CCNG7		75		4.88	483,602.5	3,152,710.0
CCNG5		50		5.29	483,720.0	3,151,920.0
Fuel Oil Firing						
CCFO1	8-Hour	100	1987	3.19	484,685.0	3,148,700.0
CCFO7		75		3.09	484,685.0	3,148,700.0
CCFO5		50		4.41	486,302.5	3,150,110.0
CCFO1		100	1988	3.54	483,902.5	3,152,310.0
CCFO7		75		3.26	483,902.5	3,152,210.0
CCFO5		50		4.96	484,802.5	3,152,410.0
CCFO1		100	1989	3.33	485,302.5	3,153,210.0
CCFO7		75		3.28	485,102.5	3,152,910.0
CCFO5		50		4.84	481,002.5	3,150,810.0
CCFO1		100	1990	2.81	485,820.0	3,149,700.0
CCFO7		75		2.79	484,202.5	3,153,310.0
CCFO5		50		4.16	484,202.5	3,153,210.0
CCFO1		100	1991	3.08	483,602.5	3,153,310.0
CCFO7		75		3.19	483,602.5	3,153,310.0
CCFO5		50		5.04	483,720.0	3,151,920.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-5
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM_{10}

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1987	0.03	480,302.5	3,149,310.0
CC7		75		0.03	481,002.5	3,149,710.0
CC5		50		0.05	481,602.5	3,150,010.0
CC1		100	1988	0.03	480,902.5	3,149,610.0
CC7		75		0.03	481,402.5	3,149,910.0
CC5		50		0.04	481,785.0	3,150,120.0
CC1		100	1989	0.03	483,702.5	3,153,310.0
CC7		75		0.03	483,702.5	3,153,210.0
CC5		50		0.05	483,702.5	3,152,910.0
CC1		100	1990	0.04	481,002.5	3,149,510.0
CC7		75		0.04	481,402.5	3,149,810.0
CC5		50		**0.06**	481,785.0	3,150,020.0
CC1		100	1991	0.04	483,602.5	3,153,310.0
CC7		75		0.04	483,602.5	3,153,210.0
CC5		50		0.05	483,602.5	3,152,910.0

*CC=Combined Cycle; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-6
ISCST3 Model Predicted Maximum 24-Hour Concentrations of PM/PM_{10}

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
Natural Gas Firing						
CCNG1	24-Hour	100	1987	0.38	484,202.5	3,152,910.0
CCNG7		75		0.39	485,820.0	3,150.200.0
CCNG5		50		0.54	485,820.0	3,150,200.0
CCNG1		100	1988	0.40	481,785.0	3,148,920.0
CCNG7		75		0.43	484,502.5	3,152,110.0
CCNG5		50		0.63	484,402.5	3,152,010.0
CCNG1		100	1989	0.44	481,785.0	3,150,120.0
CCNG7		75		0.41	481,785.0	3,150,120.0
CCNG5		50		0.55	484,202.5	3,153,210.0
CCNG1		100	1990	0.42	484,102.5	3,152,810.0
CCNG7		75		0.39	484,002.5	3,152,610.0
CCNG5		50		0.56	481,785.0	3,150,020.0
CCNG1		100	1991	0.41	485,820.0	3,150,300.0
CCNG7		75		0.45	483,802.5	3,152,510.0
CCNG5		50		**0.65**	483,720.0	3,151,920.0
Fuel Oil Firing						
CCFO1	24-Hour	100	1987	0.25	484,685.0	3,148,700.0
CCFO7		75		0.31	487,802.5	3,149,310.0
CCFO5		50		0.47	486,702.5	3,149,810.0
CCFO1		100	1988	0.30	484,002.5	3,152,410.0
CCFO7		75		0.33	484,002.5	3,152,410.0
CCFO5		50		0.47	484,802.5	3,152,410.0
CCFO1		100	1989	0.31	481,202.5	3,149,810.0
CCFO7		75		0.36	481,402.5	3,149,910.0
CCFO5		50		0.49	481,402.5	3,149,910.0
CCFO1		100	1990	0.27	484,302.5	3,153,810.0
CCFO7		75		0.32	484,202.5	3,153,310.0
CCFO5		50		0.44	481,702.5	3,149,810.0
CCFO1		100	1991	0.27	486,102.5	3,149,910.0
CCFO7		75		0.34	483,720.0	3,151,920.0
CCFO5		50		0.55	483,720.0	3,151,920.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-7
ISCST3 Model Predicted Maximum Annual Concentrations of SO_2

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1987	0.04	480,302.5	3,149,310.0
CC7		75		0.04	481,002.5	3,149,710.0
CC5		50		0.04	481,602.5	3,150,010.0
CC1		100	1988	0.04	480,902.5	3,149,610.0
CC7		75		0.04	481,402.5	3,149,910.0
CC5		50		0.04	481,785.0	3,150,120.0
CC1		100	1989	0.04	483,702.5	3,153,310.0
CC7		75		0.04	483,702.5	3,153,210.0
CC5		50		0.05	483,702.5	3,152,910.0
CC1		100	1990	0.05	481,002.5	3,149,510.0
CC7		75		0.05	481,402.5	3,149,810.0
CC5		50		**0.05**	481,785.0	3,150,020.0
CC1		100	1991	0.04	483,602.5	3,153,310.0
CC7		75		0.05	483,602.5	3,153,210.0
CC5		50		0.05	483,602.5	3,152,910.0

*CC=Combined Cycle; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-8
ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	UTM Location East (m)	UTM Location North (m)
Natural Gas Firing						
CCNG1	3-Hour	100	1987	0.68	483,802.5	3,152,010.0
CCNG7		75		0.46	483,502.5	3,152,410.0
CCNG5		50		0.46	483,502.5	3,152,310.0
CCNG1		100	1988	0.55	483,220.0	3,151,920.0
CCNG7		75		0.45	484,502.5	3,152,110.0
CCNG5		50		0.48	484,320.0	3,151,920.0
CCNG1		100	1989	0.55	481,785.0	3,150,020.0
CCNG7		75		0.42	485,720.0	3,151,920.0
CCNG5		50		0.42	483,702.5	3,152,310.0
CCNG1		100	1990	0.57	481,785.0	3,149,820.0
CCNG7		75		0.44	481,602.5	3,151,310.0
CCNG5		50		0.43	481,785.0	3,151,220.0
CCNG1		100	1991	0.53	483,320.0	3,151,920.0
CCNG7		75		0.43	482,802.5	3,152,910.0
CCNG5		50		0.41	483,502.5	3,152,510.0
Fuel Oil Firing						
CCFO1	3-Hour	100	1987	8.06	483,402.5	3,153,210.0
CCFO7		75		7.87	483,402.5	3,153,110.0
CCFO5		50		8.15	483,402.5	3,152,810.0
CCFO1		100	1988	**8.91**	483,202.5	3,152,010.0
CCFO7		75		8.44	483,220.0	3,151,920.0
CCFO5		50		8.53	483,220.0	3,151,920.0
CCFO1		100	1989	8.29	485,820.0	3,149,300.0
CCFO7		75		7.31	486,502.5	3,152,210.0
CCFO5		50		7.65	486,002.5	3,152,010.0
CCFO1		100	1990	8.18	481,202.5	3,149,410.0
CCFO7		75		7.96	481,302.5	3,149,510.0
CCFO5		50		8.27	481,602.5	3,149,710.0
CCFO1		100	1991	8.34	486,802.5	3,149,710.0
CCFO7		75		7.61	483,302.5	3,152,110.0
CCFO5		50		7.71	483,302.5	3,152,010.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-9
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO_2

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	UTM Location East (m)	UTM Location North (m)
Natural Gas Firing						
CCNG1	24-Hour	100	1987	0.11	484,202.5	3,152,910.0
CCNG7		75		0.10	485,820.0	3,150,200.0
CCNG5		50		0.11	485,820.0	3,150,200.0
CCNG1		100	1988	0.12	481,785.0	3,148,920.0
CCNG7		75		0.11	484,502.5	3,152,110.0
CCNG5		50		0.12	484,402.5	3,152,010.0
CCNG1		100	1989	0.13	481,785.0	3,150,120.0
CCNG7		75		0.10	481,785.0	3,150,120.0
CCNG5		50		0.11	484,202.5	3,153,210.0
CCNG1		100	1990	0.12	484,102.5	3,152,810.0
CCNG7		75		0.10	484,002.5	3,152,610.0
CCNG5		50		0.11	481,785.0	3,150,020.0
CCNG1		100	1991	0.12	485,820.0	3,150,300.0
CCNG7		75		0.11	483,802.5	3,152,510.0
CCNG5		50		0.13	483,720.0	3,151,920.0
Fuel Oil Firing						
CCFO1	24-Hour	100	1987	1.61	484,685.0	3,148,700.0
CCFO7		75		1.59	487,802.5	3,149,310.0
CCFO5		50		1.87	486,702.5	3,149,810.0
CCFO1		100	1988	1.89	484,002.5	3,152,410.0
CCFO7		75		1.69	484,002.5	3,152,410.0
CCFO5		50		1.88	484,802.5	3,152,410.0
CCFO1		100	1989	1.93	481,202.5	3,149,810.0
CCFO7		75		1.82	481,402.5	3,149,910.0
CCFO5		50		1.95	481,402.5	3,149,910.0
CCFO1		100	1990	1.67	484,302.5	3,153,810.0
CCFO7		75		1.63	484,202.5	3,153,310.0
CCFO5		50		1.78	481,702.5	3,149,810.0
CCFO1		100	1991	1.68	486,102.5	3,149,910.0
CCFO7		75		1.73	483,720.0	3,151,920.0
CCFO5		50		2.20	483,720.0	3,151,920.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

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 (μg/m³)*	PSD Class II Significant Impact Level (μg/m³)	PSD De Minimis Monitoring Level (μg/m³)
NO_x	Annual	0.11	1	14
CO	1-Hour	55.91	2,000	N/A
	8-Hour	14.14	500	575
PM/PM_{10}	Annual	0.06	1	N/A
	24-Hour	0.65	5	10
SO_2	Annual	0.05	1	N/A
	3-Hour	8.91	25	N/A
	24-Hour	2.20	5	13

*The maximum impacts per pollutant were the highest impact per scenario based on the five years of data (1987-1990), and are identified in Tables 4-2 through 4-9.

5.0 Additional and Class I Area Impact Analyses

As part of the air impact evaluation for the Project, the FDEP has requested that analyses of the Project's effect on the Chassahowitzka National Wildlife Refuge (CNWR) be performed. The CNWR is a Federal Prevention of Significant Deterioration (PSD) Class I area located in west central Florida approximately 140 km west-northwest of the Project. Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in these air analyses are regional haze, deposition, and Class I Significant Impact Levels (SILs). Figure 5-1 presents the locations of the Project with respect to the CNWR.

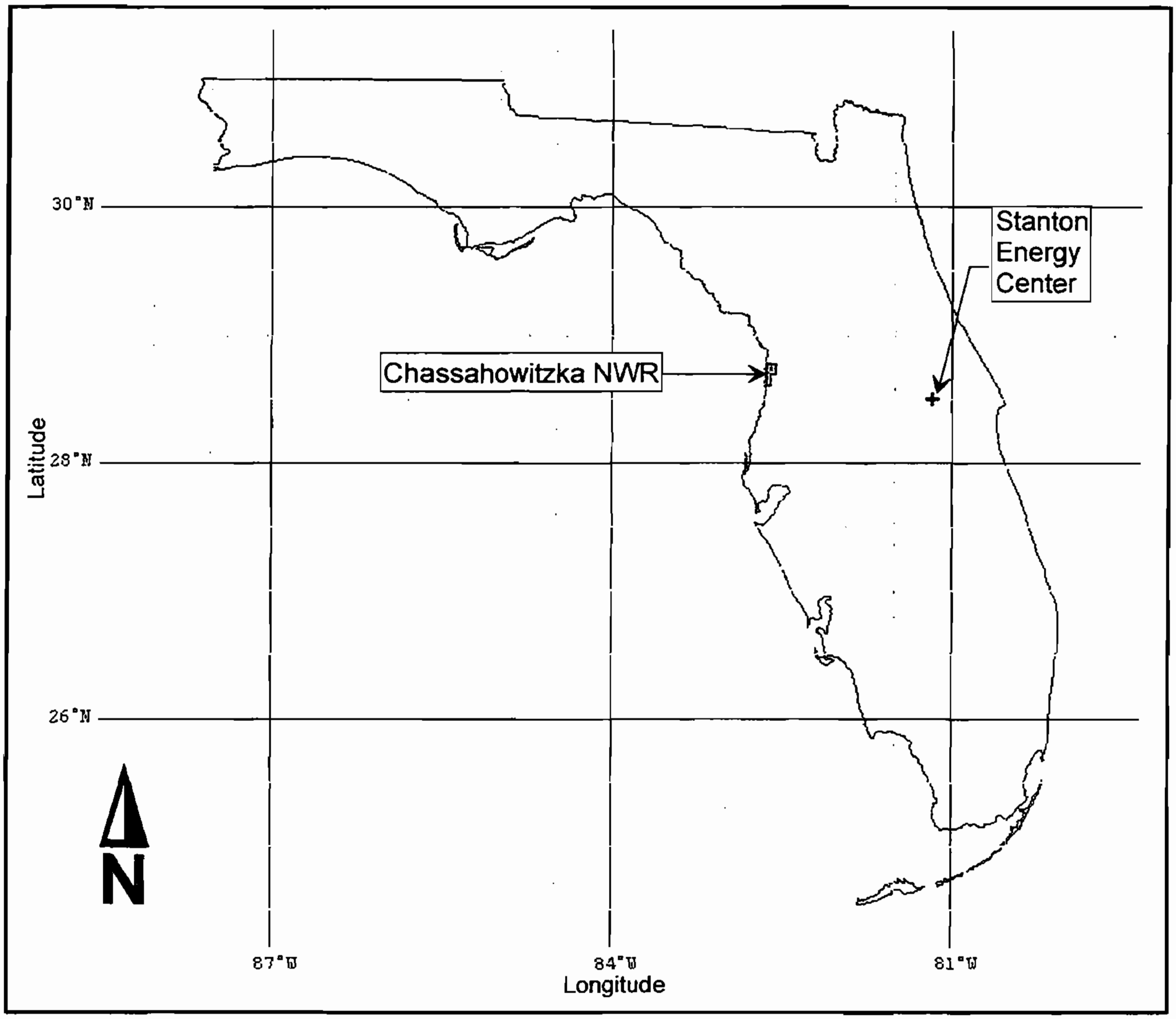
The air analyses closely follow those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I & II* reports dated April 1993 and December 1998, respectively, the *Draft Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* dated October 1999, as well as coordination with the FDEP who has communicated as necessary with the United States Fish and Wildlife Service (USFWS), which is the Federal Land Manager (FLM) for the area. The air analyses also followed a mutually agreed upon methodology discussed at a meeting with FDEP on May 31, 2000, submitted to FDEP on behalf of OUC in a letter from Black & Veatch dated August 30, 2000. A copy of the methodology submitted to FDEP is presented in Attachment 5.

This section includes a discussion of the meteorological and geophysical databases used in the analyses, the preparation of those databases for introduction into the modeling system, the air modeling approach, and the modeling results.

5.1 Model Selection and Inputs

The California Puff (CALPUFF, Version 5.4) air dispersion modeling system was used to determine the maximum ground level impacts of those PSD pollutants for which the Project is significant and which have applicable significant impact levels for a Class I area (i.e., NO_x, PM/PM_{10}, and SO_2).

CALPUFF is a non-steady state, Lagrangian, Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analyses. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs



Location of Stanton Energy Center with Respect to Chassahowitzka National Wildlife Refuge

Figure 5-1

Class I and Stanton.srf

that extract data from large databases and convert the data into formats suitable for input to CALMET. For the analyses, the processed data produced from CALMET was input to CALPUFF to assess pollutant specific impacts. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase I and II reports and Draft Phase I FLAG report. To model the emissions associated with the two CCCT/HRSGs at the Project and assess the AQRVs at the CNWR.

5.1.1 CALPUFF Model Settings

The CALPUFF settings contained in Table 5-1 were used for the modeling analyses.

5.1.2 Building Wake Effects

The CALPUFF analyses include the Project's building dimensions to account for the effects of building-induced downwash on the emission sources. As discussed in Section 4.2.3, dimensions for all significant building structures were processed with BPIP and included in the CALPUFF model input.

5.1.3 Receptor Locations

The CALPUFF analyses used an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the CNWR. Specifically, the array consists of 14 discrete receptors and was obtained from the FDEP via email from Alex Meng on June 20, 2000. The refined CALPUFF receptors for the CNWR are shown in Figure 5-2.

5.1.4 Meteorological Data Processing

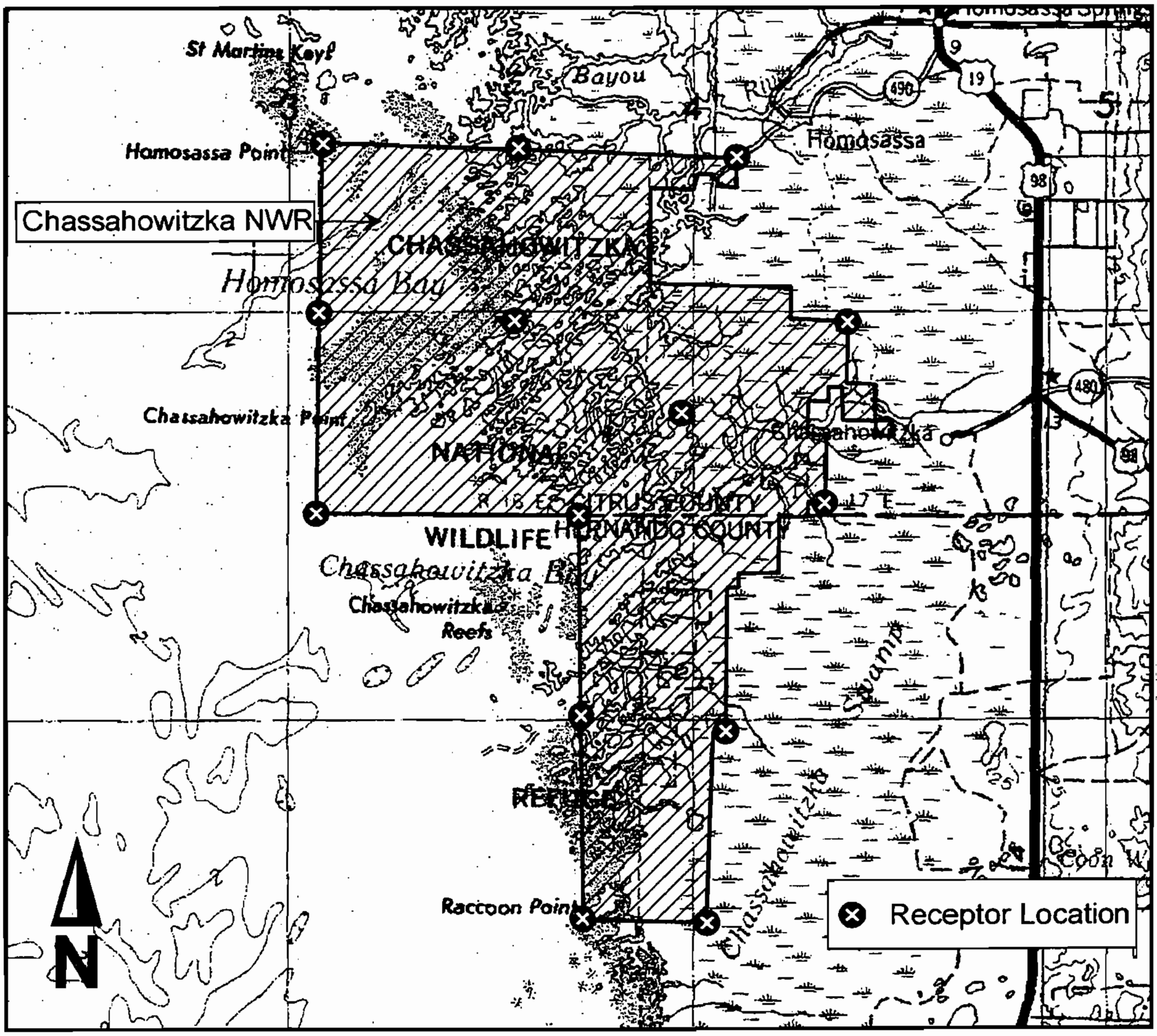
The CALPUFF analyses employed the California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.2) to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data used and processed in the CALMET model.

5.1.4.1 CALMET Settings The CALMET settings, including horizontal and vertical grid coverage, number of weather stations (sea surface, land surface, upper air, and precipitation), and resolution of prognostic mesoscale meteorological data, are contained in Table 5-2.

5.1.4.2 Modeling Domain A rectangular modeling domain extending 350 km in the east-west (x) direction and 290 km in the north-south (y) direction was used for the refined modeling analysis. The boundary of the domain is represented by the dashed line

Table 5-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Vertical Wind Shear, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour SO_4, NO_3 and PM_{10} concentrations for the year. Deposition: Highest predicted annual, SO_2, SO_4, NO_3, NO_x, and HNO_3 values in deposition units. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Ozone = 80 ppb; Ammonia =10 ppb



Chassahowitzka National Wildlife Refuge Receptors

Figure 5-2

Chassahowitzka.srf

Table 5-2 CALMET Settings	
PARAMETER	**SETTING**
Horizontal Grid Dimensions	350 by 290 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	1 sea surface, 6 land surface, 3 upper air, 27 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 8 x 6 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

in Figure 5-3. The southwest corner of the domain is the origin and is located at 27 N degrees latitude and 83.5 W degrees longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. The size of the domain used for the modeling was based on the distances needed to cover the area from the Project to the receptors at the CNWR with an 80-km buffer zone in each direction.

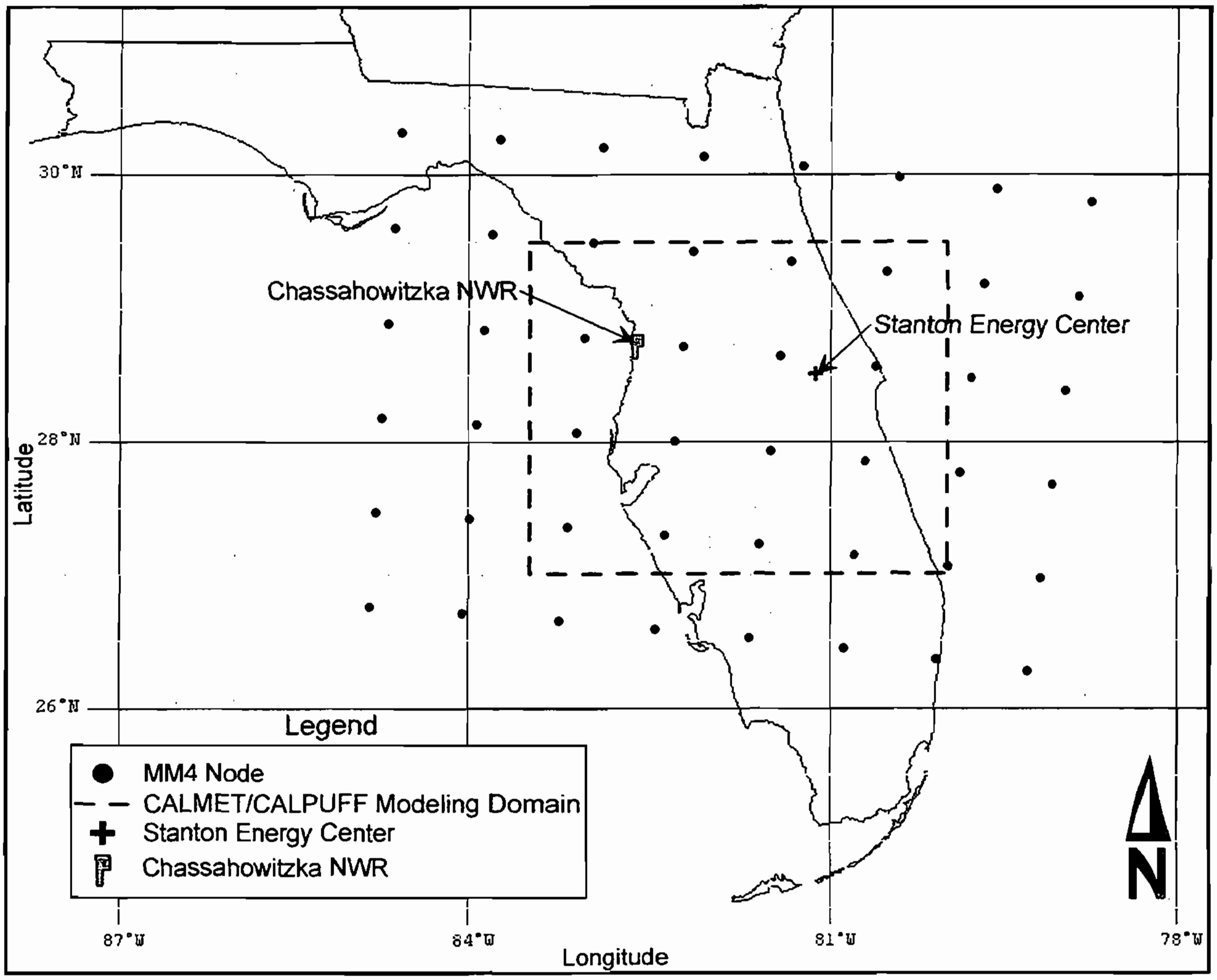
For the processing of meteorological and geophysical data, 70 grid cells were used in the x-direction and 58 grid cells were used in the y-direction. A 5-km grid spacing was used. The air modeling analyses were performed in the UTM coordinate system.

5.1.4.3 Mesoscale Model Data Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analyses used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

To apply a national MM4 dataset to the modeling domain, a sub-set domain was developed that fully enclosed the area of the modeling domain. The MM4 subset domain consisted of an 8 x 6-cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (49,10) to (56, 15). These data were processed to create a MM4.DAT file, for input to the CALMET model. The MM4 subset domain is represented by the MM4 node points in Figure 5-3.

The MM4 data set used in CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

5.1.4.4 Surface Data Stations and Processing The surface station data processed for the CALPUFF analyses consisted of data from six National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations for Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers,and Orlando. Because the modeling domain origin extends over water, C-Man station data from Venice is included



CALMET/CALPUFF Modeling Domain

Figure 5-3

Domain.srf

in the wind field. These data were processed by the FDEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. A summary of the surface station information and locations is presented in Table 5-3 and Figure 5-4, respectively. The land surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The sea surface station data include wind direction, wind speed, and air temperature.

The land surface weather station data for all stations but Gainesville was downloaded for the year 1990 from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD-ROM set. The surface data from Gainesville was processed from NCDC CD-144 format. The entire land surface data set was processed with the CALMET preprocessor utility program, SMERGE, to create one surface file, SURF.DAT.

5.1.4.5 Upper Air Data Stations and Processing The analysis included three upper air NWS stations located in Ruskin, West Palm Beach, and Apalachicola. Data for these stations was obtained from the FDEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table 5-3 and Figure 5-4, respectively.

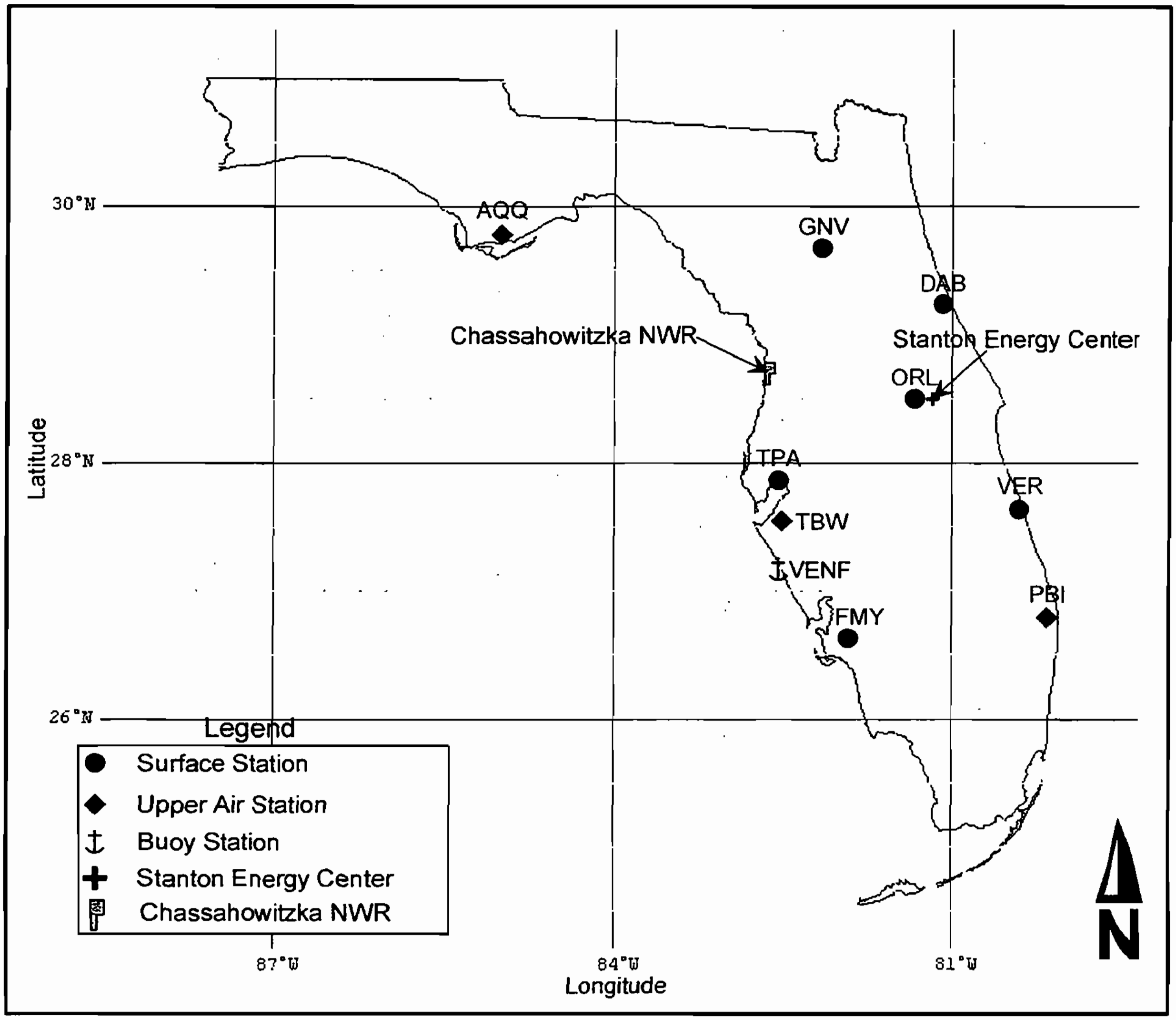
5.1.4.6 Precipitation Data Stations and Processing Precipitation data was processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations located within or just beyond the modeling domain (dashed rectangular box in Figure 5-3). They were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were used to process the data into the format for the PRECIP.DAT file for use in CALMET. A listing of the precipitation stations used for the modeling analyses is presented in Table 5-4 and are shown in Figure 5-5.

5.1.4.7 Geophysical Data Processing Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS) web site. The DEM data was extracted for the modeling domain grid using the utility extraction program TERREL. Land-use data was obtained from the 1-degree USGS files and processed using the utility programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once processed, all of the land-use parameters were combined with the terrain

Table 5-3
Meteorological Stations Used in the CALPUFF Analysis

Station Name	Station Symbol[a]	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Daytona Beach, FL	DAB	12834	495.14	3,228.05	17	9.1
Fort Myers, FL	FMY	12835	413.65	2,940.38	17	6.1
Gainesville, FL	GNV	12816	377.40	3,284.12	17	6.7
Orlando, FL	ORL	12815	468.96	3,146.88	17	10.1
Tampa, FL	TPA	12842	349.20	3,094.25	17	6.7
Vero Beach, FL	VER	12843	557.52	3,058.36	17	6.7
Upper Air Stations						
Apalachicola, FL	AQQ	12832	110.00[b]	3,296.00	16	N/A
Ruskin, FL	TBW	12842	349.20	3,094.28	17	N/A
West Palm Beach, FL	PBI	12844	587.87	2,951.42	17	N/A
Sea Stations						
Venice	VENF	N/A	356.20	2,994.80	17	7.3

[a] Meteorological station location shown by station symbol on Figure 5-4.
[b] Equivalent Coordinate for Zone 17.

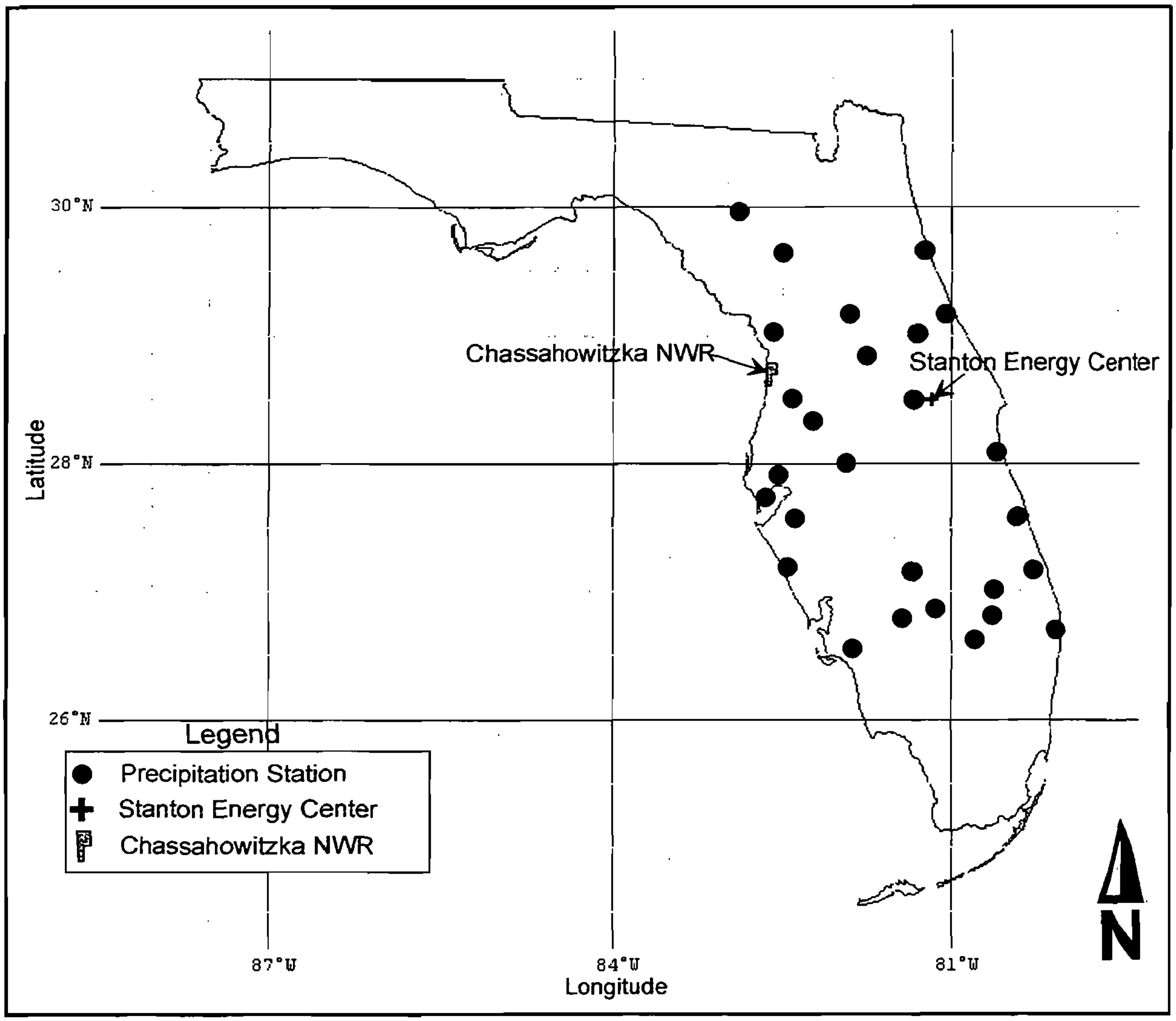


Surface and Upper Air Meteorological Stations

Figure 5-4

Met Stations.srf

Table 5-4 **Hourly Precipitation Stations Used in the CALPUFF Analysis**				
Station Name	Station Number	UTM Coordinates		
Florida		Easting (km)	Northing (km)	Zone
Belle Glade Hrcn Gt 4	80616	528.190	2,953.034	17
Branford	80975	315.606	3,315.955	17
Brooksville 7 SSW	81048	358.029	3,149.545	17
Canal Point Gate 5	81271	536.428	2,971.514	17
Daytona Beach WSO AP	82158	494.165	3,227.413	17
Deland 1 SSE	82229	470.780	3,209.660	17
Fort Myers FAA/AP	83186	413.992	2,940.710	17
Gainesville 11 WNW	83322	355.411	3,284.205	17
Inglis 3 E	84273	342.631	3,211.652	17
Lakeland	84797	409.871	3,099.178	17
Lisbon	85076	423.594	3,193.256	17
Lynne	85237	409.255	3,230.295	17
Marineland	85391	479.193	3,282.030	17
Melbourne WSO	85612	534.381	3,109.967	17
Moore Haven Lock 1	85895	491.608	2,967.803	17
Orlando WSO McCoy	86628	468.169	3,145.102	17
Ortona Lock 2	86657	470.174	2,962.267	17
Parrish	86880	366.986	3,054.394	17
Port Mayaca S L Canal	87293	538.044	2,984.440	17
Saint Leo	87851	376.483	3,135.086	17
St Lucie New Lock 1	87859	571.042	2,999.353	17
St Petersburg	87886	339.608	3,071.991	17
Tampa Wscmo AP	88788	348.478	3,093.670	17
Venice	89176	357.593	2,998.178	17
Venus	89184	467.266	3,001.224	17
Vero Beach 4 W	89219	554.268	3,056.498	17
West Palm Beach	89525	589.611	2,951.627	17



Precipitation Stations

Figure 5-5

Precip Stations.srf

information with the utility program MAKEGEO into a GEO.DAT file for input to CALMET. The land-use parameter values were based on annual averaged values.

5.1.5 Facility Emissions

As discussed in Section 2.3, performance data for the combustion turbines was based on vendor data at certain design ambient temperatures at base load operation, considering both natural gas and distillate fuel oil firing. The maximum pound per hour emission rates of the four representative ambient temperatures at base load operation for both natural gas and distillate fuel oil firing were considered for the modeling. Since distillate oil operation contains higher emission rates, it was assumed that the oil cases would produce the highest impacts and were therefore used in the modeling. The emission rates and stack parameters are listed in Table 5-5.

5.2 Class I Analyses

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the CNWR, including regional haze, deposition (both sulfur and nitrogen), and Class I SILs. The following analyses were performed as described below.

5.3 Regional Haze Analyses

A regional haze analysis was performed, using the CALPUFF modeling system, for the Class I area for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

5.3.1 Visibility

Visibility is an AQRV for the CNWR. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances. According to Appendix W to Part 51, Guideline on Air Quality Models, long range transport is defied as distances beyond 50 km. Since all portions of the Class I area lie beyond 50 km from the Project, the change in visibility was analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current guidelines characterize a change in visibility by either of the following methods:

- Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
- Change in the light-extinction coefficient (b_{ext}).

Table 5-5
Stack Parameters and Pollutant Emissions Used in the CALPUFF Analysis

Stack No.	Easting (m)	Northing (m)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)*	Exit Temp (K)*	Pollutant Emission Rate (g/s)*		
							NO_x	SO_2	PM_{10}
1	438,609	3,151,119	48.77	5.79	19.90	406.48	10.04	13.48	2.14
2	438,609	3,151,082	48.77	5.79	19.90	406.48	10.04	13.48	2.14

*Assumes operation on distillate fuel oil at 100 percent load will yield worst-case impacts.

Visual range can be related to extinction with the following equation:

$$bext(Mm-1) = 3912 / vr(Mm-1)$$

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, 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.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by the percentage change in extinctions. The change is defined as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} 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_{extb}, or percent change in extinction. Based on the IWAQM Phase II guidance, if the change in extinction is less than 5 percent, no further analysis is required.

5.3.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual range of 65 km for the CNWR was obtained from the USFWS. The average relative humidity factor for each species' worst day was computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity was obtained by using Table 2.A-1 of Appendix 2.A of the Draft Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) were then used to determine the average relative humidity factor for that day (24-hour period).

5.3.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analyses followed the recommendations contained in the IWAQM Phase I and II Summary Reports and Recommendations for Modeling Long Range Transport Impacts, (EPA, 4/93 and 12/98). Table 5-6 summarizes the IWAQM recommendations. The typical calculation methodology used to compute the results of the regional haze analysis is illustrated below.

Calculation

Refined impacts are calculated as follows:

1. Obtain maximum 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   - $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   - $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   - NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3
   - NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   $b_{exts} = 3 \times NH_4NO_3 \times f(RH) + 3 \times (NH_4)_2SO_4 \times f(RH) + 1 \times PM_{10}$
5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) obtained from the USFWS:

   $b_{extb} = 3.912 / \text{Visual range (km)}$
6. Compute the change in extinction coefficients:

   in terms of percent change of visibility:

   $\Delta\% = (b_{exts} / b_{extsb}) \times 100$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the Project's emissions should then be compared to a 5 percent change in light extinction of the background levels.

Table 5-6
Outline of IWAQM Refined Modeling Analyses Recommendations*

Meteorology	Refined CALPUFF Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Refined CALPUFF Within Class I area(s) of concern.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO_4, NO_3, and PM_{10} values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the supplied background extinction.

*IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 12/98).

5.3.4 Visibility/Regional Haze Results

The CALPUFF air modeling system was used to assess regional haze impacts at the Class I area from the Project. The results from the refined CALPUFF modeling at CNWR are presented in Table 5-7. The maximum predicted change is 0.81 percent. This impact is below the 5 percent change criteria indicating that the Project operation does not adversely impact the existing regional haze at the CNWR. Electronic copies of the modeled inputs and outputs are presented in Attachment 6.

5.4 Deposition Analysis

Deposition analyses were performed for the CNWR for both total sulfur and nitrogen. The analyses followed those procedures and methodologies set forth in the IWAQM Phase I Report. Specifically, deposition analyses were performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned (including output of both dry and wet deposition).
2. Perform individual CALPOST post-processor runs to output the maximum 24-hour average wet and dry deposition impacts of SO_2, SO_4, NO_3, NO_x, and HNO_3 in $\mu g/m^2/s$ units.
3. Apply the appropriate scaling factors to the above CALPOST runs to account for the conversion of micrograms to kilograms, square meters to hectares (ha), seconds to hours, and hours to a day. Thus, the CALPOST results are output in kg/hectare.
4. For sulfur deposition, sum the results of both the wet deposition and dry deposition values for the SO_2 and SO_4 CALPOST runs.
5. For nitrogen deposition, sum the results of both the wet deposition and dry deposition values for the NO_3, NO_x, and HNO_3 CALPOST runs.

The results of the sulfur and nitrogen deposition analyses for CNWR are presented in Table 5-8. Currently, there are no published threshold values for comparison, the values presented in the table are for review and evaluation by the FLM. However, it is assumed that these insignificant impacts are well below harmful levels.

5.5 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) at the CNWR were calculated for the criteria pollutants that exceed PSD Significant Emission Levels (SELs) and also have PDS Class I significant increment levels to compare for each applicable averaging period (i.e.,

Table 5-7
CALPUFF Refined Analysis Results on CNWR

Item	Predicted Worst Days (Year – Day)		
	1990 – 085	1990 – 019	1990 – 019
Maximum Predicted Conc. (μg/m^3)			
SO_4	0.023824	0.006075	0.006075
NO_3	0.012852	0.018666	0.018666
PM_{10}	0.012248	0.021756	0.021756
Average Relative Humidity Factor[a]	2.4	4.8	4.8
Background Visual Range[b], Vr (km)	65	65	65
Background Extinction Coeff. (b_{extb}) (Mm^{-1})	60.2	60.2	60.2
Source Extinction Coeff. (b_{exts}) (Mm^{-1})[c]			
$(NH_4)_2SO_4$	0.235858	0.120285	0.120285
NH_4NO_3	0.119369	0.346740	0.346740
PM_{10}	0.012248	0.021756	0.021756
Total (b_{exts}) (Mm^{-1})	0.37	0.49	0.49
Percent Change (%)	0.61	0.81	0.81

Table 5-8
CNWR Sulfur and Nitrogen Deposition Results

Pollutant	Dry Deposition[a] (kg/hectare)	Wet Deposition[a] (kg/hectare)	Total Deposition[a] (kg/hectare)
SO_2	3.3889E-03	2.3031E-03	5.6920E-03
SO_4	1.2061E-05	9.0206E-04	9.1412E-04
Total Sulfur[b]	3.4010E-03	3.2052E-03	6.6062E-03
NO_3	5.7721E-06	2.8592E-04	2.9169E-04
NO_x	2.9132E-04	N/A[d]	2.9132E-04
HNO_3	3.6589E-04	2.5640E-04	6.2229E-04
Total Nitrogen[c]	6.6298E-04	5.4232E-04	1.2053E-03

[a]Values are computed from annual average model predicted impacts.
[b]Total sulfur is the sum of SO_2 and SO_4.
[c]Total nitrogen is the sum of NO_3, NO_x and HNO_3.
[d]Wet Deposition does not consider NO_x.

NO_x – Annual, PM_{10} – Annual, PM_{10} – 24 hour, SO_2 – Annual, SO_2 – 3 hour, and SO_2 – 24 hour). As noted in Section 2.5.1, CO also exceeded PSD SELs. However, there is no Class I increment for this pollutant and therefore it was not considered.

As in the regional haze analyses, CALPUFF was used for CNWR. For conservatism, the distillate fuel oil emission rates and stack parameters, from Table 5-5, were again assumed to yield the worst-case pollutant impacts and were therefore used in this analysis. Specifically, these short-term emission rates on oil were modeled in CALPUFF to yield both short-term and annual pollutant impacts at the Class I area. On an annual bases, the CALPUFF model conservatively assumed 8,760 hours of operation on oil although a maximum 1,000 hours of operation on fuel oil firing has been requested.

The results of this analysis, presented in Table 5-9, are compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I increment values. As the results in Table 5-9 demonstrate, there are no exceedances of the Class I SILs. Therefore, no further analyses are warranted.

5.6 Commercial, Residential, and Industrial Growth

The Project is at the Stanton Energy Center Facility near the city of Orlando within Orange 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 supplied 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 new, permanent jobs, which will be created by the Project. 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 Project will be very small, compared to the overall population size of the surrounding area.

5.7 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, CO, PM/PM_{10}, and SO_2, below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

Table 5-9
CNWR Class I Significant Impact Level (SIL) Results

Pollutant	Impact ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
NO_x – Annual	0.002	2.5	0.10
PM_{10} – Annual	0.001	4	0.16
PM_{10} – 24 Hour	0.022	8	0.32
SO_2 – Annual	0.007	2	0.08
SO_2 – 3 Hour	0.309	25	1.00
SO_2 – 24 Hour	0.116	5	0.20

*Class I Significant Impact Levels calculated as 4 percent of the Class I Increment Levels.

The criteria pollutants, which triggered an additional impact analysis, include NO_x, CO, PM/PM_{10}, and SO_2. The modeled impacts were compared to the secondary NAAQS as the basis for assessing cumulative impacts. The results of the air dispersion modeling in Section 4.0 showed that the NO_x, CO, PM/PM_{10}, and SO_2 impacts are below the PSD Class II SILs and therefore are below the NAAQS. 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.

6.0 Hazardous Air Pollutants

The following sections discuss the Project's hazardous air pollutant impact analyses.

6.1 Maximum Achievable Control Technology (MACT) Determination

The following section provides a discussion of the applicability of the National Emission Standards for Hazardous Air Pollutants (NESHAP) to the Project and the necessity of applying a Maximum Achievable Control Technology (MACT).

6.1.1 NESHAPs

Presently there is not a NESHAP that governs stationary gas turbines. Nonetheless, under the Requirements for Control Technology Determinations for Major Sources contained under Clean Air Act Sections 112(g) and 112(j) and codified under Title 40 Part 63 of the Code of Federal Regulations (40 CFR 63), any person who constructs a new major sources or major modification of Hazardous Air Pollutants (HAPs) may have to apply controls governed by a standard of MACT. To "construct a major source" means to "fabricate, erect, or install...a new process or production unit which in and of itself emits or has the potential-to-emit 10 tpy of any HAP or 25 tpy of any combination of HAP". The Project would be classified as a "process unit", thus it must be determined if the Project will have a potential-to-emit 10 tpy of any one HAP or 25 tpy of any combination of HAPs

6.1.2 Potential-To-Emit Hazardous Air Pollutants and MACT Applicability

The air toxics emission rates for the combustion turbine were estimated based on the EPA document Compilation of Air Pollutant Emission Factors (AP-42) factors from Section 3.1 – Stationary Gas Turbines and the duct burner emissions were estimated based on AP-42 Section 1.4 – Natural Gas Combustion for External Combustion Sources. Formaldehyde emission rates for both natural gas and distillate oil were taken from the AP-42 Section 3 Emission Factor Query. The analysis assumed a conservative worst-case operating scenario of two CCCT/HRSGs operating 8,760 hours firing natural gas with 8,760 hours of natural gas duct firing and 1,000 hours of power augmentation, plus 1,000 hours of distillate fuel oil firing per CCCT.

MACT applicability calculations were performed and are included in Attachment 3. As demonstrated in Attachment 3, no individual HAP has a potential to be emitted in excess of 10 tpy and no combination of HAPs has a potential to be emitted in excess of 25 tpy from the operation of the Project. The individual HAP with the greatest emissions is Hexane with a potential-to-emit of 8.4 tpy. The potential-to-emit of all HAPs combined is 18.0 tpy for the Project. Because, the potential emissions of all HAPs, both individually and combined, are less than the major source levels, the NESHAP requirements are not applicable to the Addition and the need to apply MACT is not required.

Attachment 1
Operating Matrix

Table 1
Combustion Turbine Operating Scenarios

Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Power Augmentation	Duct Burner
Natural Gas							
1	19	100	X	X			
2	19	75	X	X			
3	19	50	X	X			
4	19	100	X	X			X
5	45	100	X	X			
6	45	75	X	X			
7	45	50	X	X			
8	45	100	X	X			X
9	60	100	X	X	X	X	X
10	70	100	X	X	X		
11	70	75	X	X			
12	70	50	X	X			
13	70	100	X	X	X		X
14	95	100	X	X	X		
15	95	75	X	X			
16	95	50	X	X			
17	95	100	X	X	X	X	X
18	95	100	X	X	X	X	X
19	95	100	X	X	X		X
Distillate Fuel Oil							
20	19	100	X	X			
21	19	75	X	X			
22	19	50	X	X			
23	45	100	X	X			
24	70	100	X	X	X		
25	95	100	X	X	X		

Attachment 2
Performance Data

GE Performance Data

Natural Gas Firing Only

Southern Co/OUC Project Gas Fuel Performance
Power Augmentation at 60F

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	BASE
Ambient Temp.	Deg F.	19.	19.	19.	60.
Ambient Relative Humid.	%	65.0	65.0	65.0	76.0
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280	280
Output	kW	188,800.	141,600.	94,400.	185,300.
Heat Rate (HHV)	Btu/kWh	10,080.	10,810.	12,930.	9,955.
Heat Cons. (HHV) X 10^6	Btu/h	1,903.1	1,530.7	1,220.6	1,844.7
Exhaust Pressure Loss	inches Water	14.66	9.17	6.28	13.61
Exhaust Flow X 10^3	lb/h	3847.	3006.	2463.	3687.
Exhaust Temp.	Deg F.	1077.	1132.	1182.	1101.
Exhaust Heat (HHV) X 10^6	Btu/h	1190.0	991.8	853.1	1165.6
Steam Flow	lb/h	0.	0.	0.	121,170.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	12.
NOx AS NO2	lb/h	62.	50.	39.	77.
CO	ppmvd	9.	9.	9.	15.
CO	lb/h	31.	25.	20.	48.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	12.	10.	15.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.	3.
Particulates (PM10 Front-half Filterable Only)	lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.90	0.90	0.85
Nitrogen	75.07	75.02	75.12	70.32
Oxygen	12.77	12.61	12.91	11.59
Carbon Dioxide	3.77	3.84	3.70	3.72
Water	7.50	7.64	7.37	13.53

SITE CONDITIONS

Elevation	ft.	105.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		Hydrogen-Cooled Generator
Combustion System		9/42 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.

IPS- version code- 2 . 2 . 0 Opt: 11 724120300
GORDONSA 11/27/00 15:02 UOC nat gas 19-60F 11-27-00.dat

Southern Co/OUC Project Gas Fuel Performance

ESTIMATED PERFORMANCE PG7241S(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	45.	45.	45.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280
Output	kW	179,700.	134,800.	89,900.
Heat Rate (HHV)	Btu/kWh	10,190.	10,960.	13,170.
Heat Cons. (HHV) X 10^6	Btu/h	1,831.1	1,477.4	1,184.
Exhaust Pressure Loss	inches Water	13.7	8.7	6.1
Exhaust Flow X 10^3	lb/h	3689.	2926.	2412.
Exhaust Temp.	Deg F.	1106.	1149.	1198.
Exhaust Heat (HHV) X 10^6	Btu/h	1151.5	963.5	833.0

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx as NO2	lb/h	60.	48.	38.
CO	ppmvd	15.	15.	15.
CO	lb/h	50.	40.	33.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
(PM10 Front-half Filterable Only)				

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.89
Nitrogen	74.65	74.63	74.74
Oxygen	12.65	12.59	12.90
Carbon Dioxide	3.77	3.80	3.66
Water	8.04	8.09	7.82

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Relative Humidity	%	76
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 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.

IPS- version code- 2 . 1 . 1 Opt: 11 724120300
GORDONSA 9/20/00 09:12 UOC nat gas 45F.dat

Southern Co/OUC Project Gas Fuel Performance
ESTIMATED PERFORMANCE PG7241S(FA)

Load Condition		BASE	75%	50%	BASE
Ambient Temp.	Deg F.	70.	70.	70.	70.
Evap. Cooler Status		On	Off	Off	On
Evap. Cooler Effectiveness	%	85			85
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280	280
Output	kW	169,100.	126,900.	84,600.	183,600.
Heat Rate (HHV)	Btu/kWh	10,375.	11,210.	13,450.	9,995.
Heat Cons. (HHV) X 10^6	Btu/h	1,754.4	1,422.5	1,137.9	1,835.1
Exhaust Loss	in. H2O	12.6	8.3	5.9	13.4
Exhaust Flow X 10^3	lb/h	3525.	2847.	2368.	3647.
Exhaust Temp.	Deg F.	1130.	1166.	1200.	1110.
Exhaust Heat (HHV) X 10^6	Btu/h	1113.7	937.4	806.4	1161.4
Steam Flow	lb/h	0.	0.	0.	119,820.
EMISSIONS					
NOx	ppmvd @ 15% O2	9.	9.	9.	12.
NOx as NO2	lb/h	57.	46.	36.	76.
CO	ppmvd	15.	15.	15.	15.
CO	lb/h	48.	38.	32.	47.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	11.	9.	15.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8	3.
Particulates	lb/h	9.0	9.0	9.0	9.0
(PM10 Front-half Filterable Only)					
EXHAUST ANALYSIS	% VOL.				
Argon		0.87	0.88	0.89	0.85
Nitrogen		73.70	73.83	73.96	69.82
Oxygen		12.40	12.48	12.86	11.42
Carbon Dioxide		3.77	3.75	3.57	3.73
Water		9.26	9.07	8.73	14.19

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Relative Humidity	%	77
Inlet Loss	in. H2O	4.
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 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.

IPS- version code- 2 . 1 . 1 Opt: 11 724120300
GORDONSA 9/20/00 09:10 UOC nat gas 70F.dat

Southern Co/OUC Project Gas Fuel Performance
ESTIMATED PERFORMANCE PG7241S(FA)

Load Condition		BASE	75%	50%	BASE
Ambient Temp.	Deg F.	95.	95.	95.	95.
Evap. Cooler Status		On	Off	Off	On
Evap. Cooler Effectiveness	%	85			85
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280	280
Output	kW	160,800.	120,600.	80,400.	176,600.
Heat Rate (HHV)	Btu/kWh	10,530.	11,430.	13,660.	10,105.
Heat Cons. (HHV) X 10^6	Btu/h	1,693.2	1,378.5	1,098.3	1,784.5
Exhaust Loss	in. H2O	11.8	8.1	5.7	12.6
Exhaust Flow X 10^3	lb/h	3409.	2794.	2342.	3524.
Exhaust Temp.	Deg F.	1143.	1182.	1200.	1128.
Exhaust Heat (HHV) X 10^6	Btu/h	1083.0	916.3	782.5	1135.3
Steam Flow	lb/h	0.	0.	0.	115,780.
EMISSIONS					
NOx	ppmvd @ 15% O2	9.	9.	9.	12.
NOx as NO2	lb/h	55.	45.	35.	74.
CO	ppmvd	15.	15.	15.	15.
CO	lb/h	45.	38.	32.	45.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	11.	9.	14.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8	2.8
Particulates (PM10 Front-half Filterable Only)	lb/h	9.0	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.				
Argon		0.87	0.89	0.88	0.83
Nitrogen		73.04	73.49	73.65	69.19
Oxygen		12.27	12.50	12.96	11.23
Carbon Dioxide		3.75	3.69	3.48	3.75
Water		10.07	9.44	9.03	15.01

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Relative Humidity	%	43
Inlet Loss	in. H2O	4.
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 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.

IPS- version code- 2 . 1 . 1 Opt: 11 724120300
GORDONSA 9/20/00 09:11 UOC nat gas 95F.dat

GE Performance Data

Fuel Oil Firing Only

Southern Co/OUC Project Fuel Oil Performance

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	19.	19.	19.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	195,800.	146,800.	97,900.
Heat Rate (HHV)	Btu/kWh	10,560.	11,340.	13,310.
Heat Cons. (HHV) X 10^6	Btu/h	2,067.6	1,664.7	1,303.
Exhaust Pressure Loss	inches Water	15.71	9.52	6.34
Exhaust Flow X 10^3	lb/h	4003.	3060.	2468.
Exhaust Temp.	Deg F.	1054.	1139.	1193.
Exhaust Heat (HHV) X 10^6	Btu/h	1192.6	1002.7	850.6
Water Flow	lb/h	130,720.	98,890.	68,730.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	336.	268.	208.
CO	ppmvd	20.	22.	30.
CO	lb/h	71.	59.	66.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	16.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	8.	6.	5.
SO2	ppmvw	12.0	13.0	12.0
SO2	lb/h	107.0	86.0	68.0
SO3	ppmvw	1.0	0.0	1.0
SO3	lb/h	7.0	6.0	4.0
Sulfur Mist	lb/h	11.0	9.0	7.0
Particulates (PM10 Front-half Filterable Only)	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.87	0.86
Nitrogen	71.98	71.94	72.56
Oxygen	11.47	11.11	11.58
Carbon Dioxide	5.44	5.67	5.47
Water	10.26	10.42	9.53

SITE CONDITIONS

Elevation	ft.	105.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Relative Humidity	%	65
Application		Hydrogen-Cooled Generator
Combustion System		9/42 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.

Distillate 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 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 2 . 0 Opt: 11 724120300
GORDONSA 11/27/00 14:57 OUC dist fuel 19F 11-27-00.dat

Southern Co/OUC Project Fuel Oil Performance

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	45.	70.	95.	19.
Ambient Relative Humid.	%	76.	77.	43.	65.
Evap. Cooler Status		Off	On	On	Off
Evap. Cooler Effectiveness	%		85	85	
Fuel Type		Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8
Output	kW	187,500.	178,500.	170,300.	195,800.
Heat Rate (HHV)	Btu/kWh	10,615.	10,700.	10,810.	10,560.
Heat Cons. (HHV) X 10^6	Btu/h	1,990.3	1,910.	1,840.9	2,067.6
Exhaust Pressure Loss	inches Water	14.5	13.3	12.5	15.7
Exhaust Flow X 10^3	lb/h	3825.	3646.	3517.	4003.
Exhaust Temp.	Deg F.	1083.	1113.	1131.	1054.
Exhaust Heat (HHV) X 10^6	Btu/h	1151.0	1115.2	1086.0	1192.6
Water Flow	lb/h	124,780.	113,060.	103,400.	130,720.

EMISSIONS

NOx (FBN ≤ 0.015%)	ppmvd @ 15% O2	42.	42.	42.	42.
NOx as NO2	lb/h	324.	311.	300.	336.
NOx (FBN = 0.05%)	ppmvd @ 15% O2	56.	56.	56.	56.
NOx as NO2	lb/h	434.	416.6	401.9	450.1
CO	ppmvd	20.	20.	20.	20.
CO	lb/h	67.	64.	61.	71.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	14.	14.	16.
VOC	ppmvw	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.	7.	8.
SO2	ppmvw	12.0	12.0	12.0	12.0
SO2	lb/h	103.0	99.0	96.0	107.0
SO3	ppmvw	1.0	1.0	1.0	1.0
SO3	lb/h	7.0	7.0	6.0	7.0
Sulfur Mist	lb/h	11.0	10.0	10.0	11.0
Particulates (PM10 Front-half Filterable Only)	lb/h	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.84	0.84	0.85
Nitrogen	71.58	70.86	70.42	71.98
Oxygen	11.32	11.09	11.00	11.47
Carbon Dioxide	5.47	5.49	5.47	5.44
Water	10.78	11.72	12.27	10.26

SITE CONDITIONS

Elevation	ft.	105.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		Hydrogen-Cooled Generator
Combustion System		9/42 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.

Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 2 . 0 Opt: 11 724120300
GORDONSA 10/30/00 13:17 OUC dist fuel revB 10-30-00.dat

GE Performance Data
Emissions Data

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 1**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**		**Natural Gas**
CT load (%)	**100**		
Over pressure	**no**		
Power Augmentation	**no**		
Stack outlet (F)	**185**		

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.77000**	4.08640	14.35093	552080.46	**12.77000**	4.08640	14.35093	552080.46	**12.77000**	4.08640	14.35093	552080.46
carbon dioxide	**3.77000**	1.65880	5.82550	224107.06	**3.77000**	1.65880	5.82550	224107.06	**3.77000**	1.65880	5.82550	224107.06
water vapor	**7.50000**	1.35000	4.74103	182387.58	**7.50000**	1.35000	4.74103	182387.58	**7.50000**	1.35000	4.74103	182387.58
nitrogen	**75.07000**	21.01960	73.81825	2839788.21	**75.07000**	21.01960	73.81825	2839788.21	**75.07000**	21.01960	73.81825	2839788.21
argon	**0.90000**	0.36000	1.26428	48636.69	**0.90000**	0.36000	1.26428	48636.69	**0.90000**	0.36000	1.26428	48636.69
		28.47480	100.00000			28.47480	100.00000			28.47480	100.00000	
NOx	0.00100	0.00046	0.00161	**62.00**	0.00100	0.00046	0.00161	**62.00**	0.00039	**0.00018**	0.00063	24.13
carbon monoxide	0.00082	0.00023	0.00081	**31.00**	0.00082	0.00023	0.00081	**31.00**	0.00082	0.00023	0.00081	31.00
hydrocarbons CH4	0.00069	0.00011	0.00039	**15.00**	0.00069	0.00011	0.00039	**15.00**	0.00069	0.00011	0.00039	**15.00**
VOC	0.00014	0.00002	0.00008	**3.00**	0.00014	0.00002	0.00008	**3.00**	0.00014	0.00002	0.00008	3.00
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00023	**9.00**		0.000	0.000	**9.00**		0.00007	0.00023	**9.00**
ammonia, NH3									0.00111	0.00019	0.00066	25.47
Total				**3847000.00**				**3847000.00**				**3847000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.80541				13.80541				13.80541			
carbon dioxide	4.07568				4.07568				4.07568			
nitrogen	81.15676				81.15676				81.15676			
argon	0.97297				0.97297				0.97297			
NOx	0.00108	10.78526	8.99447		0.00108	10.78526	8.99447		0.00042	4.19685	**3.50000**	
CO	0.00089	8.85932	7.38831		0.00089	8.85932	7.38831		0.00089	8.85932	**7.38831**	
VOC	0.00015	1.50037	1.25125		0.00015	1.50037	1.25125		0.00015	1.50037	**1.25125**	
ammonia, NH3									0.00120	11.99099	**10.00000**	

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 2**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**		**Natural Gas**
CT load (%)	**75**		
Over pressure	**no**		
Power Augmentation	**no**		
Stack outlet (F)	**170**		

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.61000**	4.03520	14.17571	426121.75	**12.61000**	4.03520	14.17571	426121.75	**12.61000**	4.03520	14.17571	426121.75
carbon dioxide	**3.84000**	1.68960	5.93559	178423.70	**3.84000**	1.68960	5.93559	178423.70	**3.84000**	1.68960	5.93559	178423.70
water vapor	**7.64000**	1.37520	4.83109	145222.70	**7.64000**	1.37520	4.83109	145222.70	**7.64000**	1.37520	4.83109	145222.70
nitrogen	**75.02000**	21.00560	73.79293	2218215.45	**75.02000**	21.00560	73.79293	2218215.45	**75.02000**	21.00560	73.79293	2218215.45
argon	**0.90000**	0.36000	1.26468	38016.41	**0.90000**	0.36000	1.26468	38016.41	**0.90000**	0.36000	1.26468	38016.41
		28.46560	100.00000			28.46560	100.00000			28.46560	100.00000	
NOx	0.00103	0.00047	0.00166	**50.00**	0.00103	0.00047	0.00166	**50.00**	0.00040	0.00018	0.00064	19.23
carbon monoxide	0.00085	0.00024	0.00083	**25.00**	0.00085	0.00024	0.00083	**25.00**	0.00085	0.00024	0.00083	25.00
hydrocarbons CH4	0.00071	0.00011	0.00040	**12.00**	0.00071	0.00011	0.00040	**12.00**	0.00071	0.00011	0.00040	**12.00**
VOC	0.00014	0.00002	0.00008	**2.40**	0.00014	0.00002	0.00008	**2.40**	0.00014	0.00002	0.00008	2.40
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00009	0.00030	**9.00**		0.00009	0.00030	**9.00**		0.00009	0.00030	**9.00**
ammonia, NH3									0.00113	0.00019	0.00068	20.30
Total				**3006000.00**				**3006000.00**				**3006000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.65310				13.65310				13.65310			
carbon dioxide	4.15764				4.15764				4.15764			
nitrogen	81.22564				81.22564				81.22564			
argon	0.97445				0.97445				0.97445			
NOx	0.00111	11.14448	9.10137		0.00111	11.14448	9.10137		0.00043	4.28569	**3.5**	
CO	0.00092	9.15439	7.47612		0.00092	9.15439	7.47612		0.00092	9.15439	**7.47612**	
VOC	0.00015	1.53794	1.25599		0.00015	1.53794	1.25599		0.00015	1.53794	**1.25599**	
ammonia, NH3									0.00122	12.24484	**10**	

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 3**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**	**Natural Gas**
CT load (%)	**50**	
Full pressure	**no**	
Power Augmentation	**no**	
Stack outlet (F)	**157**	

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.91000**	4.13120	14.50592	357280.90	**12.91000**	4.13120	14.50592	357280.90	**12.91000**	4.13120	14.50592	357280.90
carbon dioxide	**3.70000**	1.62800	5.71641	140795.24	**3.70000**	1.62800	5.71641	140795.24	**3.70000**	1.62800	5.71641	140795.24
water vapor	**7.37000**	1.32660	4.65810	114729.10	**7.37000**	1.32660	4.65810	114729.10	**7.37000**	1.32660	4.65810	114729.10
nitrogen	**75.12000**	21.03360	73.85549	1819060.68	**75.12000**	21.03360	73.85549	1819060.68	**75.12000**	21.03360	73.85549	1819060.68
argon	**0.90000**	0.36000	1.26407	31134.08	**0.90000**	0.36000	1.26407	31134.08	**0.90000**	0.36000	1.26407	31134.08
		28.47940	100.00000			28.47940	100.00000			28.47940	100.00000	
NOx	0.00098	0.00045	0.00158	**39.00**	0.00098	0.00045	0.00158	**39.00**	0.00038	0.00018	0.00062	15.18
carbon monoxide	0.00083	0.00023	0.00081	**20.00**	0.00083	0.00023	0.00081	**20.00**	0.00083	0.00023	0.00081	20.00
hydrocarbons CH4	0.00072	0.00012	0.00041	**10.00**	0.00072	0.00012	0.00041	**10.00**	0.00072	0.00012	0.00041	**10.00**
VOC	0.00014	0.00002	0.00008	**2.00**	0.00014	0.00002	0.00008	**2.00**	0.00014	0.00002	0.00008	2.00
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00010	0.00037	**9.00**		0.00010	0.00037	**9.00**		0.00010	0.00037	**9.00**
ammonia, NH3									0.00109	0.00019	0.00065	16.03
Total				**2463000.00**				**2463000.00**				**2463000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.93717				13.93717				13.93717			
carbon dioxide	3.99439				3.99439				3.99439			
nitrogen	81.09684				81.09684				81.09684			
argon	0.97161				0.97161				0.97161			
NOx	0.00106	10.58331	8.99071		0.00106	10.58331	8.99071		0.00041	4.11998	**3.5**	
CO	0.00089	8.91634	7.57459		0.00089	8.91634	7.57459		0.00089	8.91634	**7.57459**	
VOC	0.00016	1.56036	1.32555		0.00016	1.56036	1.32555		0.00016	1.56036	**1.32555**	
ammonia, NH3									0.00118	11.77138	**10**	

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 4**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**	heat input MMBtu/lb (HHV)	**498.9**	**Natural Gas**
CT load (%)	**100**			
Over pressure	**yes**			
Power Augmentation	**no**			
Stack outlet (F)	**178**			

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.77000**	4.08640	14.35093	552080.46	10.74747	3.43919	**12.12700**	469133.00	10.74747	3.43919	**12.12700**	469133.00
carbon dioxide	**3.77000**	1.65880	5.82550	224107.06	4.70628	2.07076	**7.30176**	282468.59	4.70628	2.07076	**7.30176**	282468.59
water vapor	**7.50000**	1.35000	4.74103	182387.58	9.30101	1.67418	**5.90337**	228371.87	9.30101	1.67418	**5.90337**	228371.87
nitrogen	**75.07000**	21.01960	73.81825	2839788.21	74.35386	20.81908	**73.41060**	2839889.06	74.35388	20.81908	**73.41060**	2839889.06
argon	**0.90000**	0.36000	1.26428	48636.69	0.89138	0.35655	**1.25725**	48636.72	0.89138	0.35655	**1.25725**	48636.72
		28.47480	100.00000			28.35977	99.99998			28.35977	99.99998	
NOx	0.00100	0.00046	0.00161	**62.00**	0.00162	0.00075	0.00263	101.91	0.00048	0.00022	0.00079	30.38
carbon monoxide	0.00082	0.00023	0.00081	**31.00**	0.00199	0.00056	0.00196	75.90	0.00199	0.00056	0.00196	75.90
hydrocarbons CH4	0.00069	0.00011	0.00039	**15.00**	0.00261	0.00042	0.00147	56.91	0.00261	0.00042	0.00147	56.91
VOC	0.00014	0.00002	0.00008	**3.00**	0.00050	0.00008	0.00028	10.98	0.00050	0.00008	0.00028	10.98
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00023	**9.00**		0.00008	0.00030	11.49		0.00008	0.00030	11.49
ammonia, NH3								58.51	0.00138	0.00024	0.00083	32.08
Total				**3847000.00**				**3868500.00**				**3868500.00**

	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)
oxygen	13.80541			11.84960			11.84960		
carbon dioxide	4.07568			5.18890			5.18890		
nitrogen	81.15676			81.97871			81.97871		
argon	0.97297			0.98279			0.98279		
NOx	0.00108	10.78526	8.99447	0.00179	17.90709	11.74185	0.00053	5.33773	**3.5**
CO	0.00089	8.85932	7.38831	0.00219	21.91024	14.36674	0.00219	21.91023	**14.36674**
VOC	0.00015	1.50037	1.25125	0.00055	5.54798	3.63786	0.00055	5.54798	**3.63786**
ammonia, NH3							0.00153	15.25067	**10**

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 5**

per CT/HRSG (numbers in bold are input)

3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**45**	**Natural Gas**
CT load (%)	**100**	
Over pressure	**no**	
Power Augmentation	**no**	
Stack outlet (F)	**181**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.65000**	4.04800	14.24750	525590.31	**12.65000**	4.04800	14.24750	525590.31	**12.65000**	4.04800	14.24750	525590.31
carbon dioxide	**3.77000**	1.65880	5.83838	215377.77	**3.77000**	1.65880	5.83838	215377.77	**3.77000**	1.65880	5.83838	215377.77
water vapor	**8.04000**	1.44720	5.09362	187903.73	**8.04000**	1.44720	5.09362	187903.73	**8.04000**	1.44720	5.09362	187903.73
nitrogen	**74.65000**	20.90200	73.56751	2713905.32	**74.65000**	20.90200	73.56751	2713905.32	**74.65000**	20.90200	73.56751	2713905.32
argon	**0.89000**	0.35600	1.25299	46222.86	**0.89000**	0.35600	1.25299	46222.86	**0.89000**	0.35600	1.25299	46222.86
		28.41200	100.00000			28.41200	100.00000			28.41200	100.00000	
NOx	0.00100	0.00046	0.00163	**60.00**	0.00100	0.00046	0.00163	**60.00**	0.00039	0.00018	0.00063	23.21
carbon monoxide	0.00138	0.00039	0.00136	**50.00**	0.00138	0.00039	0.00136	**50.00**	0.00138	0.00039	0.00136	50.00
hydrocarbons CH4	0.00072	0.00012	0.00041	**15.00**	0.00072	0.00012	0.00041	**15.00**	0.00072	0.00012	0.00041	**15.00**
VOC	0.00014	0.00002	0.00008	**3.00**	0.00014	0.00002	0.00008	**3.00**	0.00014	0.00002	0.00008	3.00
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00024	**9.00**		0.000	0.000	**9.00**		0.00007	0.00024	**9.00**
ammonia, NH3								38.10	0.00111	0.00019	0.00066	24.51
Total				**3689000.00**				**3689000.00**				**3689000.00**

	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)
oxygen	13.75598			13.75598			13.75598		
carbon dioxide	4.09961			4.09961			4.09961		
nitrogen	81.17660			81.17660			81.17660		
argon	0.96781			0.96781			0.96781		
NOx	0.00109	10.92415	9.04814	0.00109	10.92415	9.04814	0.00042	4.22568	**3.50000**
CO	0.00150	14.95568	12.38733	0.00150	14.95568	12.38733	0.00150	14.95528	**12.38700**
VOC	0.00016	1.57035	1.30067	0.00016	1.57035	1.30067	0.00016	1.56954	**1.30000**
ammonia, NH3							0.00121	12.07337	**10.00000**

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 6**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	45		Natural Gas									
CT load (%)	75											
Over pressure	no											
Power Augmentation	no											
Stack outlet (F)	170											
	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.59000	4.02880	14.17923	414884.13	12.59000	4.02880	14.17923	414884.13	12.59000	4.02880	14.17923	414884.13
carbon dioxide	3.80000	1.67200	5.88455	172181.86	3.80000	1.67200	5.88455	172181.86	3.80000	1.67200	5.88455	172181.86
water vapor	8.09000	1.45620	5.12505	149958.86	8.09000	1.45620	5.12505	149958.86	8.09000	1.45620	5.12505	149958.86
nitrogen	74.63000	20.89640	73.54417	2151902.50	74.63000	20.89640	73.54417	2151902.50	74.63000	20.89640	73.54417	2151902.50
argon	0.90000	0.36000	1.26701	37072.65	0.90000	0.36000	1.26701	37072.65	0.90000	0.36000	1.26701	37072.65
		28.41340	100.00000			28.41340	100.00000			28.41340	100.00000	
NOx	0.00101	0.00047	0.00164	48.00	0.00101	0.00047	0.00164	48.00	0.00039	0.00018	0.00063	18.54
carbon monoxide	0.00139	0.00039	0.00137	40.00	0.00139	0.00039	0.00137	40.00	0.00139	0.00039	0.00137	40.00
hydrocarbons CH4	0.00073	0.00012	0.00041	12.00	0.00073	0.00012	0.00041	12.00	0.00073	0.00012	0.00041	12.00
VOC	0.00015	0.00002	0.00008	2.40	0.00015	0.00002	0.00008	2.40	0.00015	0.00002	0.00008	2.40
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00009	0.00031	9.00		0.00009	0.00031	9.00		0.00009	0.00031	9.00
ammonia, NH3								30.47	0.00112	0.00019	0.00067	19.58
Total				2926000.00				2926000.00				2926000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.69818				13.69818				13.69818			
carbon dioxide	4.13448				4.13448				4.13448			
nitrogen	81.19900				81.19900				81.19900			
argon	0.97922				0.97922				0.97922			
NOx	0.00110	11.02477	9.05920		0.00110	11.02477	9.05920		0.00043	4.25939	3.5	
CO	0.00151	15.09343	12.40248		0.00151	15.09343	12.40248		0.00151	15.09407	12.403	
VOC	0.00016	1.58481	1.30226		0.00016	1.58481	1.30226		0.00016	1.58206	1.3	
ammonia, NH3									0.00122	12.16969	10	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 7**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**45**	**Natural Gas**
CT load (%)	**50**	
Over pressure	**no**	
Power Augmentation	**no**	
Stack outlet (F)	**160**	

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.90000**	4.12800	14.52028	350229.20	**12.90000**	4.12800	14.52028	350229.20	**12.90000**	4.12800	14.52028	350229.20
carbon dioxide	**3.66000**	1.61040	5.66460	136630.11	**3.66000**	1.61040	5.66460	136630.11	**3.66000**	1.61040	5.66460	136630.11
water vapor	**7.82000**	1.40760	4.95125	119424.09	**7.82000**	1.40760	4.95125	119424.09	**7.82000**	1.40760	4.95125	119424.09
nitrogen	**74.74000**	20.92720	73.61164	1775512.73	**74.74000**	20.92720	73.61164	1775512.73	**74.74000**	20.92720	73.61164	1775512.73
argon	**0.89000**	0.35600	1.25223	30203.87	**0.89000**	0.35600	1.25223	30203.87	**0.89000**	0.35600	1.25223	30203.87
		28.42920	100.00000			28.42920	100.00000			28.42920	100.00000	
NOx	0.00097	0.00045	0.00158	**38.00**	0.00097	0.00045	0.00158	**38.00**	0.00038	0.00017	0.00061	14.70
carbon monoxide	0.00139	0.00039	0.00137	**33.00**	0.00139	0.00039	0.00137	**33.00**	0.00139	0.00039	0.00137	33.00
hydrocarbons CH4	0.00074	0.00012	0.00041	**10.00**	0.00074	0.00012	0.00041	**10.00**	0.00074	0.00012	0.00041	**10.00**
VOC	0.00015	0.00002	0.00008	**2.00**	0.00015	0.00002	0.00008	**2.00**	0.00015	0.00002	0.00008	2.00
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00011	0.00037	**9.00**		0.00011	0.00037	**9.00**		0.00011	0.00037	**9.00**
ammonia, NH3								24.13	0.00108	0.00018	0.00064	15.52
Total				**2412000.00**				**2412000.00**				**2412000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.99436				13.99436				13.99436			
carbon dioxide	3.97049				3.97049				3.97049			
nitrogen	81.08049				81.08049				81.08049			
argon	0.96550				0.96550				0.96550			
NOx	0.00106	10.56274	9.04648		0.00106	10.56274	9.04648		0.00041	4.08662	**3.5**	
CO	0.00151	15.06977	12.90654		0.00151	15.06977	12.90654		0.00151	15.06797	**12.905**	
VOC	0.00016	1.59831	1.36888		0.00016	1.59831	1.36888		0.00016	1.59962	**1.37**	
ammonia, NH3									0.00117	11.67607	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 8**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**45**	heat input MMBtu/lb (HHV)	**523.7**	**Natural Gas**
CT load (%)	**100**			
Over pressure	**yes**			
Power Augmentation	**no**			
Stack outlet (F)	**175**			

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.65000**	4.04800	14.24750	525590.31	10.44518	3.34246	**11.81490**	438518.28	10.44518	3.34246	**11.81490**	438518.28
carbon dioxide	**3.77000**	1.65880	5.83838	215377.77	4.79229	2.10861	**7.45350**	276641.87	4.79229	2.10861	**7.45350**	276641.87
water vapor	**8.04000**	1.44720	5.09362	187903.73	10.00091	1.80016	**6.36321**	236174.99	10.00091	1.80016	**6.36321**	236174.99
nitrogen	**74.65000**	20.90200	73.56751	2713905.32	73.88083	20.68663	**73.12300**	2714011.33	73.88083	20.68663	**73.12300**	2714011.33
argon	**0.89000**	0.35600	1.25299	46222.86	0.88079	0.35232	**1.24537**	46222.78	0.88079	0.35232	**1.24537**	46222.78
		28.41200	100.00000			28.29018	99.99998			28.29018	99.99998	
NOx	0.00100	0.00046	0.00163	**60.00**	0.00169	0.00078	0.00275	101.90	0.00049	0.00023	0.00080	29.76
carbon monoxide	0.00138	0.00039	0.00136	**50.00**	0.00264	0.00074	0.00262	97.13	0.00264	0.00074	0.00262	97.13
hydrocarbons CH4	0.00072	0.00012	0.00041	**15.00**	0.00281	0.00045	0.00159	58.99	0.00281	0.00045	0.00159	58.99
VOC	0.00014	0.00002	0.00008	**3.00**	0.00054	0.00009	0.00031	11.38	0.00054	0.00009	0.00031	11.38
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00024	**9.00**		0.00009	0.00031	11.62		0.00009	0.00031	11.62
ammonia, NH3								58.09	0.00141	0.00024	0.00085	31.43
Total				**3689000.00**				**3711570.00**				**3711570.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.75598				11.60587				11.60587			
carbon dioxide	4.09961				5.32482				5.32482			
nitrogen	81.17660				82.09064				82.09064			
argon	0.96781				0.97867				0.97867			
NOx	0.00109	10.92415	9.04814		0.00188	18.76028	11.98213		0.00055	5.47991	**3.5**	
CO	0.00150	14.95568	12.38733		0.00294	29.37979	18.76478		0.00294	29.37980	**18.76478**	
VOC	0.00016	1.57035	1.30067		0.00060	6.02326	3.84704		0.00060	6.02327	**3.84704**	
ammonia, NH3									0.00157	15.65688	**10**	

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 9**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**60**	**Natural Gas**	
CT load (%)	**100**		
Full pressure	**yes**	Duct Burner Heat Input MMBtu/hr (HHV)	452.8
Power Augmentation	**yes**		
Stack outlet (F)	**178**		

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.59000**	3.70880	13.33592	491695.45	9.72849	3.11312	**11.23470**	416415.3	9.72849	3.11312	**11.23470**	416415.3
carbon dioxide	**3.72000**	1.63680	5.88553	216999.33	4.58697	2.01827	**7.28358**	269966.6	4.58697	2.01827	**7.28358**	269966.6
water vapor	**13.53000**	2.43540	8.75709	322874.00	15.14336	2.72580	**9.83696**	364607.9	15.14336	2.72580	**9.83696**	364607.9
nitrogen	**70.32000**	19.68960	70.79890	2610355.59	69.69872	19.51564	**70.42860**	2610443	69.69872	19.51564	**70.42860**	2610443
argon	**0.85000**	0.34000	1.22256	45075.62	0.84247	0.33699	**1.21613**	45075.98	0.84247	0.33699	**1.21613**	45075.98
		27.81060	100.00000			27.70982	99.99997			27.70982	99.99997	
NOx	0.00126	0.00058	0.00209	**77.00**	0.00184	0.00085	0.00305	113.224	0.00047	0.00022	0.00078	29.04
carbon monoxide	0.00129	0.00036	0.00130	**48.00**	0.00346	0.00097	0.00349	129.504	0.00346	0.00097	0.00349	129.50
hydrocarbons CH4	0.00071	0.00011	0.00041	**15.00**	0.00248	0.00040	0.00143	53.0352	0.00248	0.00040	0.00143	53.0352
VOC	0.00014	0.00002	0.00008	**3.00**	0.00082	0.00013	0.00047	17.4896	0.00082	0.00013	0.00047	17.49
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00024	**9.00**		0.00008	0.00030	11.264		0.00008	0.00030	11.264
ammonia, NH3								61.78	0.00135	0.00023	0.00083	30.67
Total				**3687000.00**				**3706510**				**3706510**

	CT Emissions			Duct Burner Discharge			Stack Exhaust		
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)
oxygen	13.40349			11.46461			11.46461		
carbon dioxide	4.30207			5.40555			5.40555		
nitrogen	81.32300			82.13702			82.13702		
argon	0.98300			0.99281			0.99281		
NOx	0.00146	14.60174	11.53299	0.00217	21.68519	13.64508	0.00056	5.56231	**3.5**
CO	0.00150	14.95392	11.81115	0.00407	40.74814	25.64016	0.00407	40.74814	**25.64016**
VOC	0.00016	1.63558	1.29184	0.00096	9.63036	6.05976	0.00096	9.63036	**6.05976**
ammonia, NH3							0.00159	15.89231	**10**

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 10**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Ambient temp (F)	**70**	**Natural Gas**
CT load (%)	**100**	
Over pressure	**no**	
Power Augmentation	**no**	
Stack outlet (F)	**178**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.40000**	3.96800	14.03231	494638.87	**12.40000**	3.96800	14.03231	494638.87	**12.40000**	3.96800	14.03231	494638.87
carbon dioxide	**3.77000**	1.65880	5.86613	206780.99	**3.77000**	1.65880	5.86613	206780.99	**3.77000**	1.65880	5.86613	206780.99
water vapor	**9.26000**	1.66680	5.89442	207778.24	**9.26000**	1.66680	5.89442	207778.24	**9.26000**	1.66680	5.89442	207778.24
nitrogen	**73.70000**	20.63600	72.97649	2572421.28	**73.70000**	20.63600	72.97649	2572421.28	**73.70000**	20.63600	72.97649	2572421.28
argon	**0.87000**	0.34800	1.23066	43380.63	**0.87000**	0.34800	1.23066	43380.63	**0.87000**	0.34800	1.23066	43380.63
		28.27760	100.00000			28.27760	100.00000			28.27760	100.00000	
NOx	0.00099	0.00046	0.00162	**57.00**	0.00099	0.00046	0.00162	**57.00**	0.00039	0.00018	0.00063	22.26
carbon monoxide	0.00138	0.00039	0.00136	**48.00**	0.00138	0.00039	0.00136	**48.00**	0.00138	0.00039	0.00136	48.00
hydrocarbons CH4	0.00070	0.00011	0.00040	**14.00**	0.00070	0.00011	0.00040	**14.00**	0.00070	0.00011	0.00040	**14.00**
VOC	0.00014	0.00002	0.00008	**2.80**	0.00014	0.00002	0.00008	**2.80**	0.00014	0.00002	0.00008	2.80
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00026	**9.00**		0.000	0.000	**9.00**		0.00007	0.00026	**9.00**
ammonia, NH3								36.34	0.00111	0.00019	0.00067	23.51
Total				**3525000.00**				**3525000.00**				**3525000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.66542				13.66542				13.66542			
carbon dioxide	4.15473				4.15473				4.15473			
nitrogen	81.22107				81.22107				81.22107			
argon	0.95878				0.95878				0.95878			
NOx	0.00110	10.95473	8.96143		0.00110	10.95473	8.96143		0.00043	4.27851	**3.50000**	
CO	0.00152	15.15542	12.39777		0.00152	15.15542	12.39777		0.00152	15.15541	**12.39777**	
VOC	0.00015	1.54712	1.26561		0.00015	1.54712	1.26561		0.00015	1.54712	**1.26561**	
ammonia, NH3									0.00122	12.22430	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 11**

per CT/HRSG (numbers in bold are input)

3.5ppm NOx (with natural gas), w/o CO catalyst

Ambient temp (F)	**70**	**Natural Gas**
CT load (%)	**75**	
Over pressure	no	
Power Augmentation	no	
Stack outlet (F)	**168**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.48000**	3.99360	14.11136	401750.46	**12.48000**	3.99360	14.11136	401750.46	**12.48000**	3.99360	14.11136	401750.46
carbon dioxide	**3.75000**	1.65000	5.83027	165987.65	**3.75000**	1.65000	5.83027	165987.65	**3.75000**	1.65000	5.83027	165987.65
water vapor	**9.07000**	1.63260	5.76878	164237.23	**9.07000**	1.63260	5.76878	164237.23	**9.07000**	1.63260	5.76878	164237.23
nitrogen	**73.83000**	20.67240	73.04580	2079613.96	**73.83000**	20.67240	73.04580	2079613.96	**73.83000**	20.67240	73.04580	2079613.96
argon	**0.88000**	0.35200	1.24379	35410.70	**0.88000**	0.35200	1.24379	35410.70	**0.88000**	0.35200	1.24379	35410.70
		28.30060	100.00000			28.30060	100.00000			28.30060	100.00000	
NOx	0.00099	0.00046	0.00162	**46.00**	0.00099	0.00046	0.00162	**46.00**	0.00039	0.00018	0.00063	17.86
carbon monoxide	0.00135	0.00038	0.00133	**38.00**	0.00135	0.00038	0.00133	**38.00**	0.00135	0.00038	0.00133	38.00
hydrocarbons CH4	0.00068	0.00011	0.00039	**11.00**	0.00068	0.00011	0.00039	**11.00**	0.00068	0.00011	0.00039	**11.00**
VOC	0.00014	0.00002	0.00008	**2.20**	0.00014	0.00002	0.00008	**2.20**	0.00014	0.00002	0.00008	2.20
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00009	0.00032	**9.00**		0.00009	0.00032	**9.00**		0.00009	0.00032	**9.00**
ammonia, NH3								29.26	0.00110	0.00019	0.00066	18.86
Total				**2847000.00**				**2847000.00**				**2847000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.72484				13.72484				13.72484			
carbon dioxide	4.12405				4.12405				4.12405			
nitrogen	81.19433				81.19433				81.19433			
argon	0.96778				0.96778				0.96778			
NOx	0.00109	10.93203	9.01592		0.00109	10.93203	9.01592		0.00042	4.24384	**3.5**	
CO	0.00148	14.83633	12.23589		0.00148	14.83633	12.23589		0.00148	14.83634	**12.23589**	
VOC	0.00015	1.50315	1.23969		0.00015	1.50315	1.23969		0.00015	1.50318	**1.23969**	
ammonia, NH3									0.00121	12.12526	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 12**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Ambient temp (F)	**70**	**Natural Gas**
CT load (%)	**50**	
Over pressure	**no**	
Power Augmentation	**no**	
Stack outlet (F)	**160**	

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.86000**	4.11520	14.52994	344069.09	**12.86000**	4.11520	14.52994	344069.09	**12.86000**	4.11520	14.52994	344069.09
carbon dioxide	**3.57000**	1.57080	5.54618	131333.53	**3.57000**	1.57080	5.54618	131333.53	**3.57000**	1.57080	5.54618	131333.53
water vapor	**8.73000**	1.57140	5.54830	131383.69	**8.73000**	1.57140	5.54830	131383.69	**8.73000**	1.57140	5.54830	131383.69
nitrogen	**73.96000**	20.70880	73.11861	1731448.77	**73.96000**	20.70880	73.11861	1731448.77	**73.96000**	20.70880	73.11861	1731448.77
argon	**0.89000**	0.35600	1.25696	29764.92	**0.89000**	0.35600	1.25696	29764.92	**0.89000**	0.35600	1.25696	29764.92
		28.32220	100.00000			28.32220	100.00000			28.32220	100.00000	
NOx	0.00094	0.00043	0.00152	**36.00**	0.00094	0.00043	0.00152	**36.00**	0.00037	0.00017	0.00060	14.15
carbon monoxide	0.00137	0.00038	0.00135	**32.00**	0.00137	0.00038	0.00135	**32.00**	0.00137	0.00038	0.00135	32.00
hydrocarbons CH4	0.00067	0.00011	0.00038	**9.00**	0.00067	0.00011	0.00038	**9.00**	0.00067	0.00011	0.00038	**9.00**
VOC	0.00013	0.00002	0.00008	**1.80**	0.00013	0.00002	0.00008	**1.80**	0.00013	0.00002	0.00008	1.80
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00011	0.00038	**9.00**		0.00011	0.00038	**9.00**		0.00011	0.00038	**9.00**
ammonia, NH3								23.02	0.00105	0.00018	0.00063	14.94
Total				**2368000.00**				**2368000.00**				**2368000.00**

	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)
oxygen	14.09006			14.09006			14.09006		
carbon dioxide	3.91147			3.91147			3.91147		
nitrogen	81.03429			81.03429			81.03429		
argon	0.97513			0.97513			0.97513		
NOx	0.00103	10.25562	8.90510	0.00103	10.25562	8.90510	0.00040	4.03080	**3.5**
CO	0.00150	14.97646	13.00428	0.00150	14.97646	13.00428	0.00150	14.97646	**13.00428**
VOC	0.00015	1.47425	1.28011	0.00015	1.47425	1.28011	0.00015	1.47425	**1.28011**
ammonia, NH3							0.00115	11.51656	**10**

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 13**

per CT/HRSG (numbers in bold are input)

3.5ppm NOx (with natural gas), w/o CO catalyst

Ambient temp (F)	**70**	heat input lb/MMBtu (HHV)	**439**	**Natural Gas**
CT load (%)	**100**			
Over pressure	**yes**			
Power Augmentation	**no**			
Stack outlet (F)	**172**			

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.40000**	3.96800	14.03231	494638.87	10.47473	3.35191	**11.89790**	421652.06	10.47473	3.35191	**11.89790**	421652.06
carbon dioxide	**3.77000**	1.65880	5.86613	206780.99	4.66373	2.05204	**7.28390**	258135.59	4.66373	2.05204	**7.28390**	258135.59
water vapor	**9.26000**	1.66680	5.89442	207778.24	10.96330	1.97339	**7.00473**	248242.03	10.96330	1.97339	**7.00473**	248242.03
nitrogen	**73.70000**	20.63600	72.97649	2572421.28	73.03610	20.45011	**72.58940**	2572510.26	73.03610	20.45011	**72.58940**	2572510.26
argon	**0.87000**	0.34800	1.23066	43380.63	0.86214	0.34485	**1.22409**	43380.77	0.86214	0.34485	**1.22409**	43380.77
		28.27760	100.00000			28.17231	100.00002			28.17231	100.00002	
NOx	0.00099	0.00046	0.00162	**57.00**	0.00159	0.00073	0.00260	92.12	0.00048	0.00022	0.00078	27.76
carbon monoxide	0.00138	0.00039	0.00136	**48.00**	0.00248	0.00070	0.00247	87.51	0.00248	0.00070	0.00247	87.51
hydrocarbons CH4	0.00070	0.00011	0.00040	**14.00**	0.00253	0.00040	0.00144	50.88	0.00253	0.00040	0.00144	50.88
VOC	0.00014	0.00002	0.00008	**2.80**	0.00049	0.00008	0.00028	9.82	0.00049	0.00008	0.00028	9.82
SO2	**0.00000**	0.00000	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00026	**9.00**		0.000	0.000	11.20		0.00009	0.00032	11.20
ammonia, NH3								53.09	0.00137	0.00023	0.00083	29.31
Total				**3525000.00**				**3543920.00**				**3543920.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.66542				11.76451				11.76451			
carbon dioxide	4.15473				5.23799				5.23799			
nitrogen	81.22107				82.02921				82.02921			
argon	0.95878				0.96829				0.96829			
NOx	0.00110	10.95473	8.96143		0.00179	17.87992	11.61600		0.00054	5.38737	**3.50000**	
CO	0.00152	15.15542	12.39777		0.00279	27.90418	18.12843		0.00279	27.90417	**18.12843**	
VOC	0.00015	1.54712	1.26561		0.00055	5.48199	3.56147		0.00055	5.48199	**3.56147**	
ammonia, NH3									0.00154	15.39249	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 14**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)	**95**	**Natural Gas**
CT load (%)	**100**	
Over pressure	**no**	
Power Augmentation	**no**	
Stack outlet (F)	**176**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.27000**	3.92640	13.92923	474847.55	**12.27000**	3.92640	13.92923	474847.55	**12.27000**	3.92640	13.92923	474847.55
carbon dioxide	**3.75000**	1.65000	5.85351	199546.26	**3.75000**	1.65000	5.85351	199546.26	**3.75000**	1.65000	5.85351	199546.26
water vapor	**10.07000**	1.81260	6.43035	219210.64	**10.07000**	1.81260	6.43035	219210.64	**10.07000**	1.81260	6.43035	219210.64
nitrogen	**73.04000**	20.45120	72.55234	2473309.43	**73.04000**	20.45120	72.55234	2473309.43	**73.04000**	20.45120	72.55234	2473309.43
argon	**0.87000**	0.34800	1.23456	42086.12	**0.87000**	0.34800	1.23456	42086.12	**0.87000**	0.34800	1.23456	42086.12
		28.18820	100.00000			28.18820	100.00000			28.18820	100.00000	
NOx	0.00099	0.00045	0.00161	**55.00**	0.00099	0.00045	0.00161	**55.00**	0.00039	0.00018	0.00063	21.47
carbon monoxide	0.00133	0.00037	0.00132	**45.00**	0.00133	0.00037	0.00132	**45.00**	0.00133	0.00037	0.00132	45.00
hydrocarbons CH4	0.00072	0.00012	0.00041	**14.00**	0.00072	0.00012	0.00041	**14.00**	0.00072	0.00012	0.00041	**14.00**
VOC	0.00014	0.00002	0.00008	**2.80**	0.00014	0.00002	0.00008	**2.80**	0.00014	0.00002	0.00008	2.80
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00026	**9.00**		0.000	0.000	**9.00**		0.00007	0.00026	**9.00**
ammonia, NH3									0.00110	0.00019	0.00066	22.67
Total				**3409000.00**				**3409000.00**				**3409000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.64395				13.64395				13.64395			
carbon dioxide	4.16991				4.16991				4.16991			
nitrogen	81.21873				81.21873				81.21873			
argon	0.96742				0.96742				0.96742			
NOx	0.00110	10.99362	8.96699		0.00110	10.99362	8.96699		0.00043	4.29103	**3.50000**	
CO	0.00148	14.77713	12.05304		0.00148	14.77713	12.05304		0.00148	14.77714	**12.05304**	
VOC	0.00016	1.60907	1.31244		0.00016	1.60907	1.31244		0.00016	1.60906	**1.31244**	
ammonia, NH3									0.00123	12.26009	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 15**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)	**95**		**Natural Gas**									
CT load (%)	**75**											
Over pressure	no											
Power Augmentation	no											
Stack outlet (F)	**166**											
	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.50000**	4.00000	14.15629	395526.61	**12.50000**	4.00000	14.15629	395526.61	**12.50000**	4.00000	14.15629	395526.61
carbon dioxide	**3.69000**	1.62360	5.74604	160544.25	**3.69000**	1.62360	5.74604	160544.25	**3.69000**	1.62360	5.74604	160544.25
water vapor	**9.44000**	1.69920	6.01359	168019.71	**9.44000**	1.69920	6.01359	168019.71	**9.44000**	1.69920	6.01359	168019.71
nitrogen	**73.49000**	20.57720	72.82418	2034707.56	**73.49000**	20.57720	72.82418	2034707.56	**73.49000**	20.57720	72.82418	2034707.56
argon	**0.89000**	0.35600	1.25991	35201.87	**0.89000**	0.35600	1.25991	35201.87	**0.89000**	0.35600	1.25991	35201.87
		28.25600	100.00000			28.25600	100.00000			28.25600	100.00000	
NOx	0.00099	0.00046	0.00161	**45.00**	0.00099	0.00046	0.00161	**45.00**	0.00038	0.00017	0.00062	17.29
carbon monoxide	0.00137	0.00038	0.00136	**38.00**	0.00137	0.00038	0.00136	**38.00**	0.00137	0.00038	0.00136	38.00
hydrocarbons CH4	0.00070	0.00011	0.00039	**11.00**	0.00070	0.00011	0.00039	**11.00**	0.00070	0.00011	0.00039	**11.00**
VOC	0.00014	0.00002	0.00008	**2.20**	0.00014	0.00002	0.00008	**2.20**	0.00014	0.00002	0.00008	2.20
SO2	**0.00000**	**0.00000**	**0.00000**	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00009	0.00032	**9.00**		0.00009	0.00032	**9.00**		0.00009	0.00032	**9.00**
ammonia, NH3									0.00109	0.00018	0.00065	18.26
Total				**2794000.00**				**2794000.00**				**2794000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.80300				13.80300				13.80300			
carbon dioxide	4.07465				4.07465				4.07465			
nitrogen	81.15062				81.15062				81.15062			
argon	0.98277				0.98277				0.98277			
NOx	0.00109	10.92452	9.10757		0.00109	10.92452	9.10757		0.00042	4.19825	**3.5**	
CO	0.00152	15.15561	12.63495		0.00152	15.15561	12.63495		0.00152	15.15562	**12.63495**	
VOC	0.00015	1.53550	1.28012		0.00015	1.53550	1.28012		0.00015	1.53550	**1.28012**	
ammonia, NH3									0.00120	11.99499	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 16**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)		**95**	**Natural Gas**
CT load (%)		**50**	
Full pressure	no		
Power Augmentation	no		
Stack outlet (F)		**160**	

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.96000**	4.14720	14.66592	343475.89	**12.96000**	4.14720	14.66592	343475.89	**12.96000**	4.14720	14.66592	343475.89
carbon dioxide	**3.48000**	1.53120	5.41485	126815.75	**3.48000**	1.53120	5.41485	126815.75	**3.48000**	1.53120	5.41485	126815.75
water vapor	**9.03000**	1.62540	5.74797	134617.50	**9.03000**	1.62540	5.74797	134617.50	**9.03000**	1.62540	5.74797	134617.50
nitrogen	**73.65000**	20.62200	72.92647	1707937.82	**73.65000**	20.62200	72.92647	1707937.82	**73.65000**	20.62200	72.92647	1707937.82
argon	**0.88000**	0.35200	1.24479	29153.05	**0.88000**	0.35200	1.24479	29153.05	**0.88000**	0.35200	1.24479	29153.05
		28.27780	100.00000			28.27780	100.00000			28.27780	100.00000	
NOx	0.00092	0.00042	0.00149	**35.00**	0.00092	0.00042	0.00149	**35.00**	0.00036	0.00016	0.00058	13.65
carbon monoxide	0.00138	0.00039	0.00137	**32.00**	0.00138	0.00039	0.00137	**32.00**	0.00138	0.00039	0.00137	32.00
hydrocarbons CH4	0.00068	0.00011	0.00038	**9.00**	0.00068	0.00011	0.00038	**9.00**	0.00068	0.00011	0.00038	**9.00**
VOC	0.00014	0.00002	0.00008	**1.80**	0.00014	0.00002	0.00008	**1.80**	0.00014	0.00002	0.00008	1.80
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00011	0.00036	**9.00**		0.00011	0.00038	**9.00**		0.00011	0.00038	**9.00**
ammonia, NH3									0.00102	0.00017	0.00062	14.42
Total				**2342000.00**				**2342000.00**				**2342000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	14.24645				14.24645				14.24645			
carbon dioxide	3.82544				3.82544				3.82544			
nitrogen	80.96076				80.96076				80.96076			
argon	0.96735				0.96735				0.96735			
NOx	0.00101	10.09882	8.97202		0.00101	10.09882	8.97202		0.00039	3.93957	**3.5**	
CO	0.00152	15.16884	13.47634		0.00152	15.16884	13.47634		0.00152	15.16885	**13.47634**	
VOC	0.00015	1.49318	1.32658		0.00015	1.49318	1.32658		0.00015	1.49319	**1.32658**	
ammonia, NH3									0.00113	11.25591	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 17**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)	**95**		**Natural Gas**									
CT load (%)	**100**											
Full pressure	**yes**		Duct Burner Heat Input MMBtu/hr (HHV)			472.9						
Power Augmentation	**yes**											
Stack outlet (F)	**169**											
	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.23000**	3.59360	12.99646	457995.36	9.21270	2.94806	**10.70350**	379372.713	9.21270	2.94806	**10.70350**	379372.713
carbon dioxide	**3.75000**	1.65000	5.96732	210288.38	4.69091	2.08400	**7.49374**	265606.622	4.89091	2.06400	**7.49374**	265606.622
water vapor	**15.01000**	2.70180	9.77122	344337.67	16.74735	3.01452	**10.94480**	387925.302	16.74735	3.01452	**10.94480**	387925.302
nitrogen	**69.19000**	19.37320	70.06430	2469066.02	68.52702	19.18757	**69.66410**	2469180.43	68.52702	19.18757	**69.66410**	2469160.43
argon	**0.83000**	0.33200	1.20070	42312.57	0.82202	0.32881	**1.19380**	42312.8084	**0.82202**	0.32881	**1.19380**	42312.8084
		27.65060	100.00000			27.54296	99.99994			27.54296	99.99994	
NOx	0.00126	0.00058	0.00210	**74.00**	0.00189	0.00087	0.00316	111.832	0.00048	0.00022	0.00081	28.56
carbon monoxide	0.00126	0.00035	0.00128	**45.00**	0.00361	0.00101	0.00367	130.122	0.00361	0.00101	0.00367	130.12
hydrocarbons CH4	0.00069	0.00011	0.00040	**14.00**	0.00261	0.00042	0.00152	53.7236	0.00261	0.00042	0.00152	53.7236
VOC	0.00014	0.00002	0.00008	**2.80**	0.00087	0.00014	0.00051	17.9328	0.00087	0.00014	0.00051	17.93
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	**0**	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00026	**9.00**		0.00009	0.00032	11.3645		0.00009	0.00032	11.3645
ammonia, NH3								60.93	0.00138	0.00023	0.00085	30.15
Total				**3524000.00**				**3544380**				**3544380**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.21332				11.06595				11.06595			
carbon dioxide	4.41228				5.63454				5.63454			
nitrogen	81.40958				82.31213				82.31213			
argon	0.97659				0.98738				0.98738			
NOx	0.00149	14.85165	11.44389		0.00227	22.69241	13.70583		0.00058	5.79486	**3.5**	
CO	0.00148	14.83731	11.43284		0.00434	43.37755	26.19931		0.00434	43.37755	**26.19931**	
VOC	0.00016	1.61562	1.24491		0.00105	10.46166	6.31866		0.00105	10.46165	**6.31866**	
ammonia, NH3									0.00166	16.55675	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 18**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)	**95**
CT load (%)	**100**
Full pressure	**yes**
Power Augmentation	**yes**
Stack outlet (F)	**168**

DUCT BURNER DESIGN CASE **Natural Gas**

Duct Burner Heat Input MMBtu/hr (HHV) 541.7

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.23000**	3.59360	12.99646	457995.36	8.92264	2.85525	**10.37220**	367937.199	8.92264	2.85525	**10.37220**	367937.199
carbon dioxide	**3.75000**	1.65000	5.96732	210288.38	4.82634	2.12359	**7.71432**	273653.159	4.82834	2.12359	**7.71432**	273653.159
water vapor	**15.01000**	2.70180	9.77122	344337.67	16.99754	3.05956	**11.11440**	394265.557	16.99754	3.05956	**11.11440**	394265.557
nitrogen	**69.19000**	19.37320	70.06430	2469086.02	68.43260	19.16113	**69.60630**	2469172.12	68.43260	19.16113	**69.60630**	2469172.12
argon	**0.83000**	0.33200	1.20070	42312.57	0.82088	0.32835	**1.19280**	42312.6715	0.82088	0.32835	**1.19280**	42312.6715
		27.65060	100.00000		100.00000	27.52787	100.00002			27.52787	100.00002	
NOx	0.00128	0.00058	0.00210	**74.00**	0.00198	0.00091	0.00331	117.336	0.00050	0.00023	0.00083	29.42
carbon monoxide	0.00126	0.00035	0.00128	**45.00**	0.00395	0.00111	0.00402	142.506	0.00395	0.00111	0.00402	142.51
hydrocarbons CH4	0.00069	0.00011	0.00040	**14.00**	0.00289	0.00046	0.00168	59.5028	0.00289	0.00046	0.00168	59.5028
VOC	0.00014	0.00002	0.00008	**2.80**	0.00098	0.00016	0.00057	20.1344	0.00098	0.00016	0.00057	20.13
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	0	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00026	**9.00**		0.00009	0.00033	11.7085		0.00009	0.00033	11.7085
ammonia, NH3								63.5545136	0.00142	0.00024	0.00088	31.06
Total				**3524000.00**				**3547340**				**3547340**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.21332				10.74985				10.74985			
carbon dioxide	4.41228				5.81469				5.81469			
nitrogen	81.40958				82.44647				82.44647			
argon	0.97659				0.98898				0.98898			
NOx	0.00149	14.85165	11.44389		0.00238	23.84802	13.95961		0.00060	5.97925	**3.5**	
CO	0.00148	14.83731	11.43284		0.00476	47.58323	27.85320		0.00476	47.58324	**27.8532**	
VOC	0.00016	1.61562	1.24491		0.00118	11.76515	6.88682		0.00118	11.76515	**6.88682**	
ammonia, NH3									0.00171	17.08358	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 19**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)	**95**	**Natural Gas**		
CT load (%)	**100**			
Full pressure	**yes**	Duct Burner Heat Input MMBtu/hr (HHV)		**412.7**
Power Augmentation	**no**			
Stack outlet (F)	**170**			

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**12.27000**	3.92640	13.92923	474847.55	10.40516	3.32965	**11.85480**	406237.915	10.40516	3.32965	**11.85480**	406237.915
carbon dioxide	**3.75000**	1.65000	5.85351	199546.26	4.61637	2.03120	**7.23184**	247819.247	4.61637	2.03120	**7.23184**	247819.247
water vapor	**10.07000**	1.81260	6.43035	219210.64	11.71370	2.10847	**7.50693**	257245.976	11.71370	2.10847	**7.50693**	257245.976
nitrogen	**73.04000**	20.45120	72.55234	2473309.43	72.40240	20.27267	**72.17830**	2473391.55	72.40240	20.27267	**72.17830**	2473391.55
argon	**0.87000**	0.34800	1.23456	42086.12	0.86237	0.34495	**1.22815**	42085.9986	0.86237	0.34495	**1.22815**	42085.9986
		28.18820	100.00000		100.00000	28.08694	100.00002			28.08694	100.00002	
NOx	0.00099	0.00045	0.00161	**55.00**	0.00157	0.00072	0.00257	88.016	0.00047	0.00022	0.00078	26.63
carbon monoxide	0.00133	0.00037	0.00132	**45.00**	0.00240	0.00067	0.00240	82.143	0.00240	0.00067	0.00240	82.14
hydrocarbons CH4	0.00072	0.00012	0.00041	**14.00**	0.00249	0.00040	0.00142	48.6668	0.00249	0.00040	0.00142	48.6668
VOC	0.00014	0.00002	0.00008	**2.80**	0.00048	0.00008	0.00027	9.4032	0.00048	0.00008	0.00027	9.40
SO2	**0.00000**	0.00000	0.00000	**0.00**	**0.00000**	0.00000	0.00000	0	**0.00000**	0.00000	0.00000	**0.00**
Particulate, PM-10		0.00007	0.00026	**9.00**		0.00009	0.00032	11.0635		0.00009	0.00032	11.0635
ammonia, NH3								50.8064908	0.00136	0.00023	0.00082	28.12
Total				**3409000.00**				**3426780**				**3426780**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.64395				11.78570				11.78570			
carbon dioxide	4.16991				5.22886				5.22886			
nitrogen	81.21873				82.00865				82.00865			
argon	0.96742				0.97679				0.97679			
NOx	0.00110	10.99362	8.96699		0.00178	17.76351	11.56691		0.00054	5.37501	**3.5**	
CO	0.00148	14.77713	12.05304		0.00272	27.23563	17.73480		0.00272	27.23564	**17.7348**	
VOC	0.00016	1.60907	1.31244		0.00055	5.45608	3.55279		0.00055	5.45608	**3.55279**	
ammonia, NH3									0.00154	15.35717	**10**	

Orlando Combined Cycle Emissions Revised 12/6/00 **Case 20**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**	**Distillate**
CT load (%)	**100**	
Over pressure	**no**	
Power Augmentatiomo	**no**	
Stack outlet (F)	**287**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.47000**	3.67040	12.92158	517250.76	**11.47000**	3.67040	12.92158	517250.76	**11.47000**	3.67040	12.92158	517250.76
carbon dioxide	**5.44000**	2.39360	8.42663	337317.84	**5.44000**	2.39360	8.42663	337317.84	**5.44000**	2.39360	8.42663	337317.84
water vapor	**10.26000**	1.84680	6.50163	260260.11	**10.26000**	1.84680	6.50163	260260.11	**10.26000**	1.84680	6.50163	260260.11
nitrogen	**71.98000**	20.15440	70.95321	2840256.83	**71.98000**	20.15440	70.95321	2840256.83	**71.98000**	20.15440	70.95321	2840256.83
argon	**0.85000**	0.34000	1.19696	47914.47	**0.85000**	0.34000	1.19696	47914.47	**0.85000**	0.34000	1.19696	47914.47
		28.40520	100.00000			28.40520	100.00000			28.40520	100.00000	
NOx	0.00518	0.00238	0.00839	**336.00**	0.00518	0.00238	0.00839	**336.00**	0.00123	0.00057	0.00199	79.69
carbon monoxide	0.00180	0.00050	0.00177	**71.00**	0.00180	0.00050	0.00177	**71.00**	0.00180	0.00050	0.00177	71.00
hydrocarbons CH4	0.00071	0.00011	0.00040	**16.00**	0.00071	0.00011	0.00040	**16.00**	0.00071	0.00011	0.00040	**16.00**
VOC	0.00035	0.00006	0.00020	**8.00**	0.00035	0.00006	0.00020	**8.00**	0.00035	0.00006	0.00020	8.00
SO2	**0.00000**	**0.00076**	**0.00267**	**107.00**	**0.00000**	0.00076	0.00267	**107.00**	**0.00000**	0.00076	0.00267	**107.00**
Particulate, PM-10		0.00012	0.00042	**17.00**		0.000	0.000	**17.00**		0.00012	0.00042	**17.00**
ammonia, NH3									0.00123	0.00021	0.00074	29.45
Total				**4003000.00**				**4003000.00**				**4003000.00**

	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)	(%vol dry)	(ppmvd)	(ppmvd@15%O2)
oxygen	12.78137			12.78137			12.78137		
carbon dioxide	6.06196			6.06196			6.06196		
nitrogen	80.20949			80.20949			80.20949		
argon	0.94718			0.94718			0.94718		
NOx	0.00578	57.75740	42.16571	0.00578	57.75740	42.16571	0.00137	13.69772	**10.00000**
CO	0.00201	20.05056	14.63788	0.00201	20.05056	14.63788	0.00201	20.05056	**14.63788**
VOC	0.00040	3.95363	2.88634	0.00040	3.95363	2.88634	0.00040	3.95363	**2.88634**
ammonia, NH3							0.00137	13.69772	**10.00000**

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 21**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**		**Distillate**									
CT load (%)	**75**											
Over pressure	no											
Power Augmentatiomo												
Stack outlet (F)	**262**											
	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.11000**	3.55520	12.51091	382833.82	**11.11000**	3.55520	12.51091	382833.82	**11.11000**	3.55520	12.51091	382833.82
carbon dioxide	**5.67000**	2.49480	8.77931	268647.00	**5.67000**	2.49480	8.77931	268647.00	**5.67000**	2.49480	8.77931	268647.00
water vapor	**10.42000**	1.87560	6.60032	201969.82	**10.42000**	1.87560	6.60032	201969.82	**10.42000**	1.87560	6.60032	201969.82
nitrogen	**71.94000**	20.14320	70.88483	2169075.76	**71.94000**	20.14320	70.88483	2169075.76	**71.94000**	20.14320	70.88483	2169075.76
argon	**0.87000**	0.34800	1.22463	37473.61	**0.87000**	0.34800	1.22463	37473.61	**0.87000**	0.34800	1.22463	37473.61
		28.41680	100.00000			28.41680	100.00000			28.41680	100.00000	
NOx	0.00541	0.00249	0.00876	**268.00**	0.00541	0.00249	0.00876	**268.00**	0.00128	0.00059	0.00208	63.58
carbon monoxide	0.00196	0.00055	0.00193	**59.00**	0.00196	0.00055	0.00193	**59.00**	0.00196	0.00055	0.00193	59.00
hydrocarbons CH4	0.00070	0.00011	0.00039	**12.00**	0.00070	0.00011	0.00039	**12.00**	0.00070	0.00011	0.00039	**12.00**
VOC	0.00035	0.00006	0.00020	**6.00**	0.00035	0.00006	0.00020	**6.00**	0.00035	0.00006	0.00020	6.00
SO2	**0.00000**	**0.00080**	**0.00281**	**86.00**	**0.00000**	0.00080	0.00281	**86.00**	**0.00000**	0.00080	0.00281	**86.00**
Particulate, PM-10		0.00016	0.00056	**17.00**		0.00016	0.00056	**17.00**		0.00016	0.00056	**17.00**
ammonia, NH3									0.00128	0.00022	0.00077	23.50
Total				**3060000.00**				**3060000.00**				**3060000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.40232				12.40232				12.40232			
carbon dioxide	6.32954				6.32954				6.32954			
nitrogen	80.30810				80.30810				80.30810			
argon	0.97120				0.97120				0.97120			
NOx	0.00604	60.39760	42.14924		0.00604	60.39760	42.14924		0.00143	14.32946	**10**	
CO	0.00218	21.84423	15.24427		0.00218	21.84423	15.24427		0.00218	21.84422	**15.24427**	
VOC	0.00039	3.88753	2.71296		0.00039	3.88753	2.71296		0.00039	3.88753	**2.71296**	
ammonia, NH3									0.00143	14.32946	**10**	

Orlando Combined Cycle Emissions **Revised 12/6/00** **Case 22**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**19**	**Distillate**	
CT load (%)	**50**		
Full pressure	no		
Power Augmentation	no		
Stack outlet (F)	**249**		

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.58000**	3.70560	13.00731	321020.37	**11.58000**	3.70560	13.00731	321020.37	**11.58000**	3.70560	13.00731	321020.37
carbon dioxide	**5.47000**	2.40680	8.44829	208503.84	**5.47000**	2.40680	8.44829	208503.84	**5.47000**	2.40680	8.44829	208503.84
water vapor	**9.53000**	1.71540	6.02136	148607.06	**9.53000**	1.71540	6.02136	148607.06	**9.53000**	1.71540	6.02136	148607.06
nitrogen	**72.56000**	20.31680	71.31554	1760067.62	**72.56000**	20.31680	71.31554	1760067.62	**72.56000**	20.31680	71.31554	1760067.62
argon	**0.86000**	0.34400	1.20750	29801.11	**0.86000**	0.34400	1.20750	29801.11	**0.86000**	0.34400	1.20750	29801.11
		28.48860	100.00000			28.48860	100.00000			28.48860	100.00000	
NOx	0.00522	0.00240	0.00843	**208.00**	0.00522	0.00240	0.00843	**208.00**	0.00124	0.00057	0.00200	49.27
carbon monoxide	0.00272	0.00076	0.00267	**66.00**	0.00272	0.00076	0.00267	**66.00**	0.00272	0.00076	0.00267	66.00
hydrocarbons CH4	0.00072	0.00012	0.00041	**10.00**	0.00072	0.00012	0.00041	**10.00**	0.00072	0.00012	0.00041	**10.00**
VOC	0.00036	0.00006	0.00020	**5.00**	0.00036	0.00006	0.00020	**5.00**	0.00036	0.00006	0.00020	5.00
SO2	**0.00000**	0.00078	0.00276	**68.00**	**0.00000**	0.00078	0.00276	**68.00**	**0.00000**	0.00078	0.00276	**68.00**
Particulate, PM-10		0.00020	0.00069	**17.00**		0.00020	0.00069	**17.00**		0.00020	0.00069	**17.00**
ammonia, NH3									0.00124	0.00021	0.00074	18.21
Total				**2468000.00**				**2468000.00**				**2468000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.79982				12.79982				12.79982			
carbon dioxide	6.04620				6.04620				6.04620			
nitrogen	80.20338				80.20338				80.20338			
argon	0.95059				0.95059				0.95059			
NOx	0.00577	57.69350	42.21384		0.00577	57.69350	42.21384		0.00137	13.66696	**10**	
CO	0.00301	30.07511	22.00571		0.00301	30.07511	22.00571		0.00301	30.07512	**22.00571**	
VOC	0.00040	3.98723	2.91742		0.00040	3.98723	2.91742		0.00040	3.98723	**2.91742**	
ammonia, NH3									0.00137	13.66696	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 23**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Ambient temp (F)	**45**	**Distillate**
CT load (%)	**100**	
Over pressure	no	
Power Augmentation	no	
Stack outlet (F)	**281**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.32000**	3.62240	12.77472	488633.09	**11.32000**	3.62240	12.77472	488633.09	**11.32000**	3.62240	12.77472	488633.09
carbon dioxide	**5.47000**	2.40680	8.48780	324658.27	**5.47000**	2.40680	8.48780	324658.27	**5.47000**	2.40680	8.48780	324658.27
water vapor	**10.78000**	1.94040	6.84300	261744.60	**10.78000**	1.94040	6.84300	261744.60	**10.78000**	1.94040	6.84300	261744.60
nitrogen	**71.58000**	20.04240	70.68134	2703561.15	**71.58000**	20.04240	70.68134	2703561.15	**71.58000**	20.04240	70.68134	2703561.15
argon	**0.86000**	0.34400	1.21315	46402.88	**0.86000**	0.34400	1.21315	46402.88	**0.86000**	0.34400	1.21315	46402.88
		28.35600	100.00000			28.35600	100.00000			28.35600	100.00000	
NOx	0.00522	0.00240	0.00847	**324.00**	0.00522	0.00240	0.00847	**324.00**	0.00124	0.00057	0.00201	76.70
carbon monoxide	0.00177	0.00050	0.00175	**67.00**	0.00177	0.00050	0.00175	**67.00**	0.00177	0.00050	0.00175	67.00
hydrocarbons CH4	0.00070	0.00011	0.00039	**15.00**	0.00070	0.00011	0.00039	**15.00**	0.00070	0.00011	0.00039	**15.00**
VOC	0.00035	0.00006	0.00020	**7.50**	0.00035	0.00006	0.00020	**7.50**	0.00035	0.00006	0.00020	7.50
SO2	0.00159	0.00076	0.00269	**103.00**	0.00159	0.00076	0.00269	**103.00**	0.00159	0.00076	0.00269	**103.00**
Particulate, PM-10		0.00013	0.00044	**17.00**		0.000	0.000	**17.00**		0.00013	0.00044	**17.00**
ammonia, NH3								119.74	0.00124	0.00021	0.00074	28.34
Total				**3825000.00**				**3825000.00**				**3825000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.68774				12.68774				12.68774			
carbon dioxide	6.13091				6.13091				6.13091			
nitrogen	80.22865				80.22865				80.22865			
argon	0.96391				0.96391				0.96391			
NOx	0.00585	58.52460	42.24453		0.00585	58.52460	42.24453		0.00139	13.85377	**10.00000**	
CO	0.00199	19.88237	14.35159		0.00199	19.88237	14.35159		0.00199	19.88154	**14.35100**	
VOC	0.00039	3.89487	2.81141		0.00039	3.89487	2.81141		0.00039	3.89486	**2.81141**	
ammonia, NH3									0.00139	13.85377	**10.00000**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 24**
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Ambient temp (F)	**70**	**Distillate**
CT load (%)	**100**	
Over pressure	no	
Power Augmentation	no	
Stack outlet (F)	**276**	

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.09000**	3.54880	12.56177	458002.07	**11.09000**	3.54880	12.56177	458002.07	**11.09000**	3.54880	12.56177	458002.07
carbon dioxide	**5.49000**	2.41560	8.55055	311753.21	**5.49000**	2.41560	8.55055	311753.21	**5.49000**	2.41560	8.55055	311753.21
water vapor	**11.72000**	2.10960	7.46740	272261.37	**11.72000**	2.10960	7.46740	272261.37	**11.72000**	2.10960	7.46740	272261.37
nitrogen	**70.86000**	19.84080	70.23093	2560619.76	**70.86000**	19.84080	70.23093	2560619.76	**70.86000**	19.84080	70.23093	2560619.76
argon	**0.84000**	0.33600	1.18935	43363.59	**0.84000**	0.33600	1.18935	43363.59	**0.84000**	0.33600	1.18935	43363.59
		28.25080	100.00000			28.25080	100.00000			28.25080	100.00000	
NOx	0.00524	0.00241	0.00853	**311.00**	0.00524	0.00241	0.00853	**311.00**	0.00124	0.00057	0.00202	73.70
carbon monoxide	0.00177	0.00050	0.00176	**64.00**	0.00177	0.00050	0.00176	**64.00**	0.00177	0.00050	0.00176	64.00
hydrocarbons CH4	0.00068	0.00011	0.00038	**14.00**	0.00068	0.00011	0.00038	**14.00**	0.00068	0.00011	0.00038	**14.00**
VOC	0.00034	0.00005	0.00019	**7.00**	0.00034	0.00005	0.00019	**7.00**	0.00034	0.00005	0.00019	7.00
SO2	0.00160	0.00077	0.00272	**99.00**	0.00160	0.00077	0.00272	**99.00**	0.00160	0.00077	0.00272	**99.00**
Particulate, PM-10		0.00013	0.00047	**17.00**		0.00013	0.00047	**17.00**		0.00013	0.00047	**17.00**
ammonia, NH3								114.93	0.00124	0.00021	0.00075	27.24
Total				**3646000.00**				**3646000.00**				**3646000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.56230				12.56230				12.56230			
carbon dioxide	6.21885				6.21885				6.21885			
nitrogen	80.26733				80.26733				80.26733			
argon	0.95152				0.95152				0.95152			
NOx	0.00593	59.34093	42.19700		0.00593	59.34093	42.19700		0.00141	14.06283	**10.00000**	
CO	0.00201	20.06198	14.26596		0.00201	20.06198	14.26596		0.00201	20.06198	**14.26596**	
VOC	0.00038	3.83999	2.73059		0.00038	3.83999	2.73059		0.00038	3.83998	**2.73059**	
ammonia, NH3									0.00141	14.06283	**10**	

Orlando Combined Cycle Emissions **Revised 11/15/00** **Case 25**
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Ambient temp (F)	**95**		**Distillate**									
CT load (%)	**100**											
Over pressure	no											
Power Augmentation	no											
Stack outlet (F)	**272**											
	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	**11.00000**	3.52000	12.48714	439172.73	**11.00000**	3.52000	12.48714	439172.73	**11.00000**	3.52000	12.48714	439172.73
carbon dioxide	**5.47000**	2.40680	8.53808	300284.35	**5.47000**	2.40880	8.53808	300284.35	**5.47000**	2.40680	8.53808	300284.35
water vapor	**12.27000**	2.20860	7.83497	275555.93	**12.27000**	2.20860	7.83497	275555.93	**12.27000**	2.20860	7.83497	275555.93
nitrogen	**70.42000**	19.71760	69.94785	2460065.95	**70.42000**	19.71780	69.94785	2460065.95	**70.42000**	19.71760	69.94785	2460065.95
argon	**0.84000**	0.33600	1.19195	41921.03	**0.84000**	0.33800	1.19195	41921.03	**0.84000**	0.33600	1.19195	41921.03
		28.18900	100.00000			28.18900	100.00000			28.18900	100.00000	
NOx	0.00523	0.00240	0.00853	**300.00**	0.00523	0.00240	0.00853	**300.00**	0.00124	0.00057	0.00202	71.01
carbon monoxide	0.00175	0.00049	0.00173	**61.00**	0.00175	0.00049	0.00173	**61.00**	0.00175	0.00049	0.00173	61.00
hydrocarbons CH4	0.00070	0.00011	0.00040	**14.00**	0.00070	0.00011	0.00040	**14.00**	0.00070	0.00011	0.00040	**14.00**
VOC	0.00035	0.00006	0.00020	**7.00**	0.00035	0.00006	0.00020	**7.00**	0.00035	0.00006	0.00020	7.00
SO2	0.00160	0.00077	0.00273	**96.00**	0.00160	0.00077	0.00273	**96.00**	0.00160	0.00077	0.00273	**96.00**
Particulate, PM-10		0.00014	0.00048	**17.00**		0.00014	0.00048	**17.00**		0.00014	0.00048	**17.00**
ammonia, NH3									0.00124	0.00021	0.00075	26.24
Total				**3517000.00**				**3517000.00**				**3517000.00**
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.53847				12.53847				12.53847			
carbon dioxide	6.23504				6.23504				6.23504			
nitrogen	80.26901				80.26901				80.26901			
argon	0.95748				0.95748				0.95748			
NOx	0.00596	59.58303	42.24983		0.00596	59.58303	42.24983		0.00141	14.10255	**10.00000**	
CO	0.00199	19.90357	14.11348		0.00199	19.90357	14.11346		0.00199	19.90358	**14.11346**	
VOC	0.00040	3.99703	2.83426		0.00040	3.99703	2.83426		0.00040	3.99703	**2.83426**	
ammonia, NH3									0.00141	14.10255	**10**	

Attachment 3

Potential-To-Emit (PTE), Enveloped Spreadsheet, and HAPs Analysis

Table 1
Hourly Emission Rates (Per CCCT/HRSG)

Case	Ambient Temperature (°F)	Load (%)	NOx (lb/hr)	CO (lb/hr)	PM/PM_{10} (lb/hr)	SO_2 (lb/hr)	VOC (lb/hr)
Natural Gas							
1	19	100	24.13	31.00	9.00	2.77	3.00
2	19	75	19.23	25.00	9.00	2.23	2.40
3	19	50	15.18	20.00	9.00	1.78	2.00
4	19	100	30.38	75.90	11.49	3.50	10.98
5	45	100	23.21	50.00	9.00	2.67	3.00
6	45	75	18.54	40.00	9.00	2.15	2.40
7	45	50	14.70	33.00	9.00	1.73	2.00
8	45	100	29.76	97.13	11.62	3.43	11.38
9	60	100	29.04	129.50	11.26	3.35	17.49
10	70	100	22.26	48.00	9.00	2.56	2.80
11	70	75	17.86	38.00	9.00	2.07	2.20
12	70	50	14.15	32.00	9.00	1.66	1.80
13	70	100	27.76	87.51	11.20	3.20	9.82
14	95	100	21.47	45.00	9.00	2.47	2.80
15	95	75	17.29	38.00	9.00	2.01	2.20
16	95	50	13.65	32.00	9.00	1.60	1.80
17	95	100	28.56	130.12	11.36	3.29	17.93
18	95	100	29.42	142.51	11.71	3.39	20.13
19	95	100	26.63	82.14	11.06	3.07	9.40
Maximum Emission Rate			30.38	142.51	11.71	3.50	20.13
Distillate Fuel Oil							
20	19	100	79.69	71.00	17.00	107.00	8.00
21	19	75	63.58	59.00	17.00	86.00	6.00
22	19	50	49.27	66.00	17.00	68.00	5.00
23	45	100	76.70	67.00	17.00	103.00	7.50
24	70	100	73.70	64.00	17.00	99.00	7.00
25	95	100	71.01	61.00	17.00	96.00	7.00
Maximum Emission Rate			79.69	71.00	17.00	107.00	8.00

Table 2
Annual Emission Rates

Cases[d]	No. of CCCT/HRSGs	Annual Operation (hrs/yr)	Emission Rates									
			NO_x		CO		PM/PM_{10}		SO_2		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4, 8, 8, 4, 8	2	6,760[a]	60.76	205.37	194.26	656.60	23.24	78.55	7.00	23.66	22.76	76.93
18, 18, 18, 18, 18	2	1,000[b]	58.84	29.42	285.02	142.51	23.42	11.71	6.78	3.39	40.26	20.13
20, 20, 20, 20 ,20	2	1,000[c]	159.38	79.69	142.00	71.00	34.00	17.00	214.00	107.00	16.00	8.00
Totals	2	8,760	N/A	314.48	N/A	870.11	N/A	107.26	N/A	134.05	N/A	105.06

[a]Assumes operation on natural gas (including duct burning) for 6,760 hour per year at 100% load.
[b]Assumes operation on natural gas (including duct burning and power augmentation) for 1,000 hours per year at 100% load.
[c]Assumes operation on distillate fuel oil for 1,000 hours per year at 100% load.
[d]Cases are listed respectively for the pollutants as they are listed across the top of the table.

Table 3
Fuel Flow Rates Per CTG/HRSG

Case	Ambient Temperature (°F)	Load (%)	Heat Input HHV (Btu/hr)	Fuel Rate Gas (ft^3/hr) Oil (gal/hr)
Natural Gas[a] (ft^3/hr)				
1	19	100	1.90E+09	1.94E+06
2	19	75	1.53E+09	1.56E+06
3	19	50	1.22E+09	1.25E+06
4	19	100	2.40E+09	2.45E+06
5	45	100	1.83E+09	1.87E+06
6	45	75	1.48E+09	1.51E+06
7	45	50	1.18E+09	1.21E+06
8	45	100	2.35E+09	2.40E+06
9	60	100	2.30E+09	2.34E+06
10	70	100	1.75E+09	1.79E+06
11	70	75	1.42E+09	1.45E+06
12	70	50	1.14E+09	1.16E+06
13	70	100	2.19E+09	2.24E+06
14	95	100	1.69E+09	1.73E+06
15	95	75	1.38E+09	1.41E+06
16	95	50	1.10E+09	1.12E+06
17	95	100	2.26E+09	2.30E+06
18	95	100	2.33E+09	2.37E+06
19	95	100	2.11E+09	2.15E+06
Distillate Fuel Oil[b] (gal/hr)				
20	19	100	2.07E+09	1.44E+04
21	19	75	1.66E+09	1.16E+04
22	19	50	1.30E+09	9.10E+03
23	45	100	1.99E+09	1.39E+04
24	70	100	1.91E+09	1.33E+04
25	95	100	1.84E+09	1.29E+04

[a]Based on a natural gas heat content of 23,325 Btu/lb (HHV) and density of 23.8 ft^3/lb.
[b]Based on a distillate oil heat content of 20,306 Btu/lb (HHV) and a density of 1 gal/7.05 lb.

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Revised 11/15/00
Printed 1/17/01 9:22 AM

Enveloped Representative Pollutant Emission and Stack Parameters

Combined Cycle Operation - Natural Gas

NOTE: Ref. 01/16/01 performance data. GE7FA

Load 100 percent

Case Name	Case 1	Case 4	Case 5	Case 8	Case 9	Case 10	Case 13	Case 14	Case 17	Case 18	Case 19
Ambient Temp (F)	19	19	45	45	60	70	70	95	95	95	95
Evap Cooler					X	X	X	X	X	X	X
Duct Firing (k)		X		X	X		X		X	X	X
Power Aug. (Steam Inj.)					X				X	X	
Exit Temp (F)	185	178	181	175	178	178	172	176	169	168	170
Exit Velocity (ft/s)	62.29	62.21	59.49	59.55	61.00	56.85	56.84	54.98	57.87	57.85	54.94
Emissions (lb/h)											
NOX (e)	24.13	30.38	23.21	29.76	29.04	22.26	27.76	21.47	28.56	29.42	26.63
CO	31.00	75.90	50.00	97.13	129.50	48.00	87.51	45.00	130.12	142.51	82.14
PM/PM10	9.00	11.49	9.00	11.62	11.26	9.00	11.20	9.00	11.36	11.71	11.06
SO2 (c)	2.77	3.50	2.67	3.43	3.35	2.56	3.20	2.47	3.29	3.39	3.07
VOC	3.00	10.98	3.00	11.38	17.49	2.80	9.82	2.80	17.93	20.13	9.40

Enveloped Load Representative Emissions and Stack Parameters

Exit Temp (F)	168.00	348.71	K
Exit Velocity (ft/s)	54.94	16.75	m/s
Emissions (lb/h)			
NOX	30.38	3.83	g/s
CO	142.51	17.96	g/s
PM/PM10	11.71	1.48	g/s
SO2	3.50	0.44	g/s
VOC	20.13	2.54	g/s

Load 75 percent

Case Name	Case 2	Case 6	Case 11	Case 15
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Duct Firing				
Power Aug. (Steam Inj.)				
Exit Temp (F)	170	170	168	166
Exit Velocity (ft/s)	47.55	46.38	45.16	44.25
Emissions (lb/h)				
NOX (e)	19.23	18.54	17.86	17.29
CO	25.00	40.00	38.00	38.00
PM/PM10	9.00	9.00	9.00	9.00
SO2 (c)	2.23	2.15	2.07	2.01
VOC	2.40	2.40	2.20	2.20

Exit Temp (F)	166.00	347.59	K
Exit Velocity (ft/s)	44.25	13.49	m/s
Emissions (lb/h)			
NOX	19.23	2.42	g/s
CO	40.00	5.04	g/s
PM/PM10	9.00	1.13	g/s
SO2	2.23	0.28	g/s
VOC	2.40	0.30	g/s

Load 50 percent

Case Name	Case 3	Case 7	Case 12	Case 16
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Duct Firing				
Power Aug. (Steam Inj.)				
Exit Temp (F)	157	160	160	160
Exit Velocity (ft/s)	38.14	37.60	37.06	36.71
Emissions (lb/h)				
NOX (e)	15.18	14.70	14.15	13.65
CO	20.00	33.00	32.00	32.00
PM/PM10	9.00	9.00	9.00	9.00
SO2 (c)	1.78	1.73	1.66	1.60
VOC	2.00	2.00	1.80	1.80

Exit Temp (F)	157.00	342.59	K
Exit Velocity (ft/s)	36.71	11.19	m/s
Emissions (lb/h)			
NOX	15.18	1.91	g/s
CO	33.00	4.16	g/s
PM/PM10	9.00	1.13	g/s
SO2	1.78	0.22	g/s
VOC	2.00	0.25	g/s

Combined Cycle Operation - Fuel Oil

NOTE: Ref. 01/16/01 performance data. GE7FA

Load 100 percent

Case Name	Case 20	Case 23	Case 24	Case 25
Ambient Temp (F)	19	45	70	95
Evap Cooler			X	X
Duct Firing (k)				
Power Aug. (Steam Inj.)				
Exit Temp (F)	287	281	276	272
Exit Velocity (ft/s)	75.25	71.45	67.9	65.28
Emissions (lb/h)				
NOX(e)	79.69	76.70	73.70	71.01
CO	71.00	67.00	64.00	61.00
PM/PM10	17.00	17.00	17.00	17.00
SO2 (d)	107.00	103.00	99.00	96.00
VOC	8.00	7.50	7.00	7.00

Enveloped Load Representative Emissions and Stack Parameters

Exit Temp (F)	272.00	406.48	K
Exit Velocity (ft/s)	65.28	19.90	m/s
Emissions (lb/h)			
NOX	79.69	10.04	g/s
CO	71.00	8.95	g/s
PM/PM10	17.00	2.14	g/s
SO2	107.00	13.48	g/s
VOC	8.00	1.01	g/s

Case Name	Case 21
Ambient Temp (F)	19
Evap Cooler	
Duct Firing (k)	
Power Aug. (Steam Inj.)	
Exit Temp (F)	262
Exit Velocity (ft/s)	55.57
Emissions (lb/h)	
NOX(e)	63.58
CO	59.00
PM/PM10	17.00
SO2 (d)	86.00
VOC	6.00

Exit Temp (F)	262.00	400.93	K
Exit Velocity (ft/s)	55.57	16.94	m/s
Emissions (lb/h)			
NOX	63.58	8.01	g/s
CO	59.00	7.43	g/s
PM/PM10	17.00	2.14	g/s
SO2	86.00	10.84	g/s
VOC	6.00	0.76	g/s

Case Name	Case 22
Ambient Temp (F)	19
Evap Cooler	
Duct Firing (k)	
Power Aug. (Steam Inj.)	
Exit Temp (F)	249
Exit Velocity (ft/s)	43.90
Emissions (lb/h)	
NOX(e)	49.27
CO	66.00
PM/PM10	17.00
SO2 (d)	68.00
VOC	5.00

Exit Temp (F)	249.00	393.71	K
Exit Velocity (ft/s)	43.90	13.38	m/s
Emissions (lb/h)			
NOX	49.27	6.21	g/s
CO	66.00	8.32	g/s
PM/PM10	17.00	2.14	g/s
SO2	68.00	8.57	g/s
VOC	5.00	0.63	g/s

Notes

- a Combined Total Reduced Sulfur Compounds (including H2S) and Total Reduced Sulfur (including H2S)
- b H2SO4 based on a 10% conversion of SO2 to SO3 and a molecular ratio of 1.22 from SO3 to H2SO4 (in the stack and SCR).
- c Sulfur content assumed for the Natural Gas = 0.5 grains of sulfur/100 SCF
- d Sulfur content assumed for the fuel oil = 0.05% sulfur.
- e Natural Gas NOx emissions at 3.5 ppmvd @ 15% O2. Fuel Oil NOx emissions at 10 ppmvd @ 15% O2.
- f Assumed 100% conversion of Sulfur to SO2 for natural gas.

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Hazardous Air Pollutants

Hazardous Air Pollutants[1]

Pollutant	Duct Burner – Natural Gas: Uncontrolled Emission Factor (lb/10^6 acf)[5]	Duct Burner – Natural Gas: Maximum Heat Input (Mbtu/h)	Duct Burner – Natural Gas: Facility PTE (tpy)[4]	Total from Duct Burners: Facility PTE (tpy)[4]	Combustion Turbine – Natural Gas: Uncontrolled Emission Factor (lb/MMBtu)[2,6]	Combustion Turbine – Natural Gas: Normal CTG Maximum Heat Input (Mbtu/h)[4]	Combustion Turbine – Natural Gas: CTG using Power Augmentation Maximum Heat Input (Mbtu/h)[4]	Combustion Turbine – Natural Gas: Facility PTE (tpy)	Combustion Turbine – Oil: Uncontrolled Emission Factor (lb/MMBtu)[3,7]	Combustion Turbine – Oil: Maximum Heat Input (Mbtu/h)	Combustion Turbine – Oil: Facility PTE (tpy)[4]	Total from Combustion Turbines GAS/OIL Facility PTE (tpy)	Total from CTs with Duct Burners GAS/OIL Facility PTE (tpy)
1, 3-Butadiene					4.30E-07	1903.1	1903.1	0.0072	1.60E-05	2067.6	0.0331	0.0403	4.03E-02
2-Methylnaphthalene	2.40E-05	541.7	1.12E-04	1.12E-04									1.12E-04
3-Methylchloranthrene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
7,12-Dimethylbenz(a)anthracene	1.60E-05	541.7	7.44E-05	7.44E-05									7.44E-05
Acenaphthene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Acenaphthylene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Acetaldehyde					4.00E-05	1903.1	1903.1	0.6688				0.6668	6.67E-01
Acrolein					6.40E-06	1903.1	1903.1	0.1067				0.1067	1.07E-01
Anthracene	2.40E-06	541.7	1.12E-05	1.12E-05									1.12E-05
Benz(a)anthracene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Benzene	2.10E-03	541.7	9.77E-03	9.77E-03	1.20E-05	1903.1	1903.1	0.2001	5.50E-05	2067.6	0.1137	0.3138	3.24E-01
Benzo(a)pyrene	1.20E-06	541.7	5.58E-06	5.58E-06									5.58E-06
Benzo(b)fluoranthene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Benzo(g,h,i)perylene	1.20E-06	541.7	5.58E-06	5.58E-06									5.58E-06
Benzo(k)fluoranthene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Chrysene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Dibenzo(a,h)anthracene	1.20E-06	541.7	5.58E-06	5.58E-06									5.58E-06
Dichlorobenzene	1.20E-03	541.7	5.58E-03	5.58E-03									5.58E-03
Ethylbenzene					3.20E-05	1903.1	1903.1	0.5335				0.5335	5.33E-01
Fluoranthene	3.00E-06	541.7	1.40E-05	1.40E-05									1.40E-05
Fluorene	2.80E-06	541.7	1.30E-05	1.30E-05									1.30E-05
Formaldehyde (Natural Gas CT[9]; Oil CT[10])	7.50E-02	541.7	3.49E-01	3.49E-01	8.42E-05	1903.1	1903.1	1.4037	1.80E-04	2067.6	0.3928	1.7966	2.15E+00
Hexane	1.80E+00	541.7	8.37E+00	8.37E+00									8.37E+00
Indeno(1,2,3-cd)pyrene	1.80E-06	541.7	8.37E-06	8.37E-06									8.37E-06
Napthalene	6.10E-04	541.7	2.84E-03	2.84E-03	1.30E-06	1903.1	1903.1	0.0217	3.50E-05	2067.6	0.0724	0.0940	9.69E-02
PAH					2.20E-06	1903.1	1903.1	0.0367	4.00E-05	2067.6	0.0827	0.1194	1.19E-01
Phenanathrene	1.70E-05	541.7	7.91E-05	7.91E-05									7.91E-05
Propylene Oxide					2.90E-05	1903.1	1903.1	0.4835				0.4835	4.83E-01
Pyrene	5.00E-06	541.7	2.33E-05	2.33E-05									2.33E-05
Toluene	3.40E-03	541.7	1.58E-02	1.58E-02	1.30E-04	1903.1	1903.1	2.1673				2.1673	2.18E+00
Xylenes					6.40E-05	1903.1	1903.1	1.0670				1.0670	1.07E+00
TOTAL			8.76	8.76				6.69			0.69	7.39	

Metallic Hazardous Air Pollutants[1]

Combustion Turbine – Natural Gas: No Natural Gas, Metallic HAPs listed in AP-42 for combustion turbines.

Pollutant	Duct Burner – Natural Gas: Uncontrolled Emission Factor (lb/10^6 acf)[5]	Duct Burner – Natural Gas: Maximum Heat Input (Mbtu/h)	Duct Burner – Natural Gas: Facility PTE (tpy)[4]	Total from Duct Burners: Facility PTE (tpy)	Combustion Turbine – Natural Gas	Combustion Turbine – Oil: Uncontrolled Emission Factor (lb/MMBtu)[3,8]	Combustion Turbine – Oil: Maximum Heat Input (Mbtu/h)	Combustion Turbine – Oil: Facility PTE (tpy)[4]	Total from Combustion Turbines GAS/OIL Facility PTE (tpy)	Total
Arsenic	2.00E-04	541.7	8.24E-04	8.24E-04		1.10E-05	2067.6	0.023	0.0227	2.36E-02
Beryllium	1.20E-05	541.7	4.95E-05	4.95E-05		3.10E-07	2067.6	0.001	0.0006	6.80E-04
Cadmium	1.10E-03	541.7	4.53E-03	4.53E-03		4.80E-06	2067.6	0.010	0.0099	1.45E-02
Chromium	1.40E-03	541.7	5.77E-03	5.77E-03		1.10E-05	2067.6	0.023	0.0227	2.85E-02
Cobalt	8.40E-05	541.7	3.46E-04	3.46E-04						3.46E-04
Lead						1.40E-05	2067.6	0.029	0.0289	2.89E-02
Manganese	3.80E-04	541.7	1.57E-03	1.57E-03		7.80E-04	2067.8	1.633	1.6334	1.63E+00
Mercury	2.60E-04	541.7	1.07E-03	1.07E-03		1.20E-06	2067.6	0.002	0.0025	3.55E-03
Nickel	2.10E-03	541.7	8.65E-03	8.65E-03		4.80E-06	2067.8	0.010	0.0095	1.62E-02
Selenium	2.40E-05	541.7	9.89E-05	9.89E-05		2.50E-05	2067.6	0.052	0.0517	5.18E-02
TOTAL			2.29E-02	2.29E-02	-			1.78	1.78	
TOTAL				8.78					9.17	17.95

Notes

[1] Factors are derived for 2 units operating at high loads (>=80 percent load) only.

[2] The AP-42 emission factors were based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60 degrees F.

[3] The AP-42 emission factors were based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons.

[4] Fuel oil operation per year based on 1000 hours. Natural gas operation based on 7760 hours of normal operation and 1000 hours of power augmentation.

[5] From AP-42 (7/98) Table 1.4-3 and 1.4-4 and listed as a HAP as defined by Section 112(b) of the Clean Air Act.

[6] From AP-42 (7/98) Table 3.1-3.

[7] From AP-42 (7/98) Table 3.1-4.

[8] From AP-42 (7/98) Table 3.1-5.

[9] Formaldehyde emission factor from AP-42 Ch.3 Emission Factor Query for Natural Gas.

[10] Formaldehyde emission factor from AP-42 Ch 3 Emission Factor Query for Fuel Oil

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Heat Input

Revised 5/25/00

Printed 1/17/01 9:29 AM

Combined Cycle Operation - Natural Gas

NOTE: Ref. 11/16/01 performance data.

Load 100 percent — GE7FA

Case Name	Case 1	Case 4	Case 5	Case 8	Case 9	Case 10	Case 13	Case 14	Case 17	Case 18	Case 19
Ambient Temp (F)	19	19	45	45	60	70	70	95	95	95	95
Evap Cooler					X	X	X	X	X	X	X
Duct Firing (k)		X		X	X		X		X	X	X
Power Augmentation (Steam Inj.)					X				X	X	
CTG Heat Input HHV (Btu/hr)	1.90E+09	1.90E+09	1.83E+09	1.83E+09	1.84E+09	1.75E+09	1.75E+09	1.69E+09	1.78E+09	1.78E+09	1.69E+09
Duct Burner Heat Input HHV (Btu/hr)	0	4.99E+08	0	5.24E+08	4.53E+08	0	4.39E+08	0	4.73E+08	5.42E+08	4.13E+08
Total Heat Input HHV (Btu/hr)	1.90E+09	2.40E+09	1.83E+09	2.35E+09	2.30E+09	1.75E+09	2.19E+09	1.69E+09	2.26E+09	2.33E+09	2.11E+09
Fuel Rate (cu ft/hr)	1.94E+06	2.45E+06	1.87E+06	2.40E+06	2.34E+06	1.79E+06	2.24E+06	1.73E+06	2.30E+06	2.37E+06	2.15E+06

Load 75 percent

Case Name	Case 2	Case 6	Case 11	Case 15
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Duct Firing				
Power Augmentation (Steam Inj.)				
CTG Heat Input HHV (Btu/hr)	1.53E+09	1.48E+09	1.42E+09	1.38E+09
Duct Burner Heat Input HHV (Btu/hr)	0	0	0	0
Total Heat Input HHV (Btu/hr)	1.53E+09	1.48E+09	1.42E+09	1.38E+09
Fuel Rate (cu ft/hr)	1.56E+06	1.51E+06	1.45E+06	1.41E+06

Load 50 percent

Case Name	Case 3	Case 7	Case 12	Case 16
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Duct Firing				
Power Augmentation (Steam Inj.)				
CTG Heat Input HHV (Btu/hr)	1.22E+09	1.18E+09	1.14E+09	1.10E+09
Duct Burner Heat Input HHV (Btu/hr)	0	0	0	0
Total Heat Input HHV (Btu/hr)	1.22E+09	1.18E+09	1.14E+09	1.10E+09
Fuel Rate (cu ft/hr)	1.25E+06	1.21E+06	1.16E+06	1.12E+06

Combined Cycle Operation - Fuel Oil

NOTE: Ref. 11/16/01 performance data.

Load 100 percent — GE7FA

Case Name	Case 20	Case 23	Case 24	Case 25
Ambient Temp (F)	19	45	70	95
Evap Cooler			X	X
Duct Firing (k)				
Power Augmentation (Steam Inj.)				
CTG Heat Input HHV (Btu/hr)	2.07E+09	1.99E+09	1.91E+09	1.84E+09
Duct Burner Heat Input HHV (Btu/hr)	0	0	0	0
Total Heat Input HHV (Btu/hr)	2.07E+09	1.99E+09	1.91E+09	1.84E+09
Fuel Rate (gal/hr)	1.44E+04	1.39E+04	1.33E+04	1.29E+04

Case Name	Case 21
Ambient Temp (F)	19
Evap Cooler	
Duct Firing (k)	
Power Augmentation (Steam Inj.)	
CTG Heat Input HHV (Btu/hr)	1.66E+09
Duct Burner Heat Input HHV (Btu/hr)	0
Total Heat Input HHV (Btu/hr)	1.66E+09
Fuel Rate (gal/hr)	1.16E+04

Case Name	Case 22
Ambient Temp (F)	19
Evap Cooler	
Duct Firing (k)	
Power Augmentation (Steam Inj.)	
CTG Heat Input HHV (Btu/hr)	1.30E+09
Duct Burner Heat Input HHV (Btu/hr)	0
Total Heat Input HHV (Btu/hr)	1.30E+09
Fuel Rate (gal/hr)	9.10E+03

COOLING TOWER EMISSION RATE ESTIMATES

Particulate matter (PM/PM_{10}) emissions from the induced draft mechanical cooling tower were estimated using procedures found in AP42, Section 13.4, Wet Cooling Towers.

A. Cooling Tower Data

Total Liquid Drift = 0.002% of recirculation water flow rate
Total Liquid Drift = 0.002 gal/100 gal recirculation water flow rate

Recirculation Water Flow Rate = 125,000 gal/min

Recirculation Water Total Dissolved Solids (TDS) = 3,704

B. PM/PM_{10} Emission Rate Calculations

PM/PM_{10} = (125,000 gal / min) x (0.002 gal / 100 gal H_2O) x (8.345 lb / gal H_2O) x (3,704 lb PM/PM_{10} / 10^6 lb water) x (60 min / hr)

PM/PM_{10} = 4.64 lb/hr

PM/PM_{10} = 20.32 ton/yr (8,760 hours/year operation)

Attachment 4
Best Available Control Technology

Best Available Control Technology Analysis
for the
Stanton Energy Center Combined Cycle
Combustion Turbine Project

Submitted by

Orlando Utilities Commission
Kissimmee Utility Authority
Florida Municipal Power Authority
and
Southern Company-Florida, LLC

Prepared by
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January 2001
Project No. 98362

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1.0 Executive Summary

The 1977 Clean Air Act Amendment (CAAA) 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 two-combined cycle combustion turbines and one cooling tower that are subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this project.

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for Orlando Utilities Corporation (OUC). The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for the BACT analysis are based on each combustion turbine-generator/heat recovery steam generator (CTG/HRSG) unit operating at three different operating conditions. These three conditions are 1) natural gas operation at full load with duct burner firing for 6,760 hours per year, 2) natural gas firing with power augmentation for 1,000 hours per year at an ambient temperature of 70 F with the CT and duct burner firing at full load, and 3) fuel oil firing of the combustion turbine-generator (CTG) unit at full load operation without duct firing for 1,000 hours per year at an ambient temperature of 70 F.

GE PG7241(FA) CTG/HRSG Units:

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

- Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O_2.
- Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O_2.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O_2 (without power augmentation) and 26.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O_2 during fuel oil firing.

Particulate (PM/PM_{10}) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O_2 (without power augmentation) and 6.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O_2 during fuel oil firing.

Sulfur Dioxide (SO_2) Emissions – BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

2.0 Project Description

The electric generating facility (hereinafter referred to as the "Project") to be installed for OUC will consist of two (2) General Electric (GE) PG7241(FA) combined cycle combustion turbines (CCCT) and one (1) cooling tower. The combined cycle operation consists of using two combustion turbines and two-heat recovery steam generators (HRSGs) with a steam turbine in a Rankine power cycle. The configuration is used to generate additional power. Although the CTG/HRSG power plant is well suited for continuous operation at full load, it is not well suited for large load changes or quick and frequent startups and shutdowns. Each CTG/HRSG configuration will also include a supplemental duct burner (DB) located in the outlet duct from the combustion turbine to provide additional heat for high power demand periods. The HRSG will be used to recover energy from the high temperature flue gas generated by each combustion turbine and duct burner. A steam turbine will be used to generate additional electricity from the steam produced in the HRSG. The steam from the HRSG may also be injected into the combustion turbine to increase power during peak electrical demands. The use of steam injection power augmentation can also improve the efficiency of the combustion turbine. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas.

The output ratings of each GE PG7241(FA) combine cycle combustion turbine will be nominally 170 MW. The proposed operating scenario for the combustion turbines consists of operating up to 7,760 hours per year while firing natural gas and operating up to 1,000 hours per year while firing fuel oil. As with most combustion turbine facilities that have been permitted in the United States, the use of fuel oil will be considered as a backup fuel to natural gas for this project and the balance of this facility's operation is expected to consist of firing natural gas. For the purposes of this analysis, worst case annual operation and emissions were evaluated. This is equivalent to natural gas operation at 6,670 hours per year at full load with duct firing, natural gas firing at full load for 1,000 hours per year at full load with duct firing and power augmentation, and fuel oil firing at full load for 1,000 hours per year.

3.0 Basis of Combustion Turbine BACT Analysis

This section describes the basis of the combustion turbine BACT analysis. Information is provided on such issues as the BACT methodology and approach used. The parameters and factors used in developing the analysis are identified.

3.1 Regulatory and Methodology Basis

The BACT analysis for the GE PG7241(FA) combustion turbine units with and without duct burner firing is based on certain regulatory requirements and project assumptions. The following is a summary of the requirements and assumptions on which this BACT analysis is based.

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal New Source Performance Standards (NSPS) for combustion turbines with heat input greater than 10 mmBtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for NO_x emissions. No NSPS criteria have been established for limiting CO, VOC and PM/PM_{10} emissions. The following flue gas emission limit is 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.
- Federal NSPS for electric utility steam generating units for which construction is commenced after September 18, 1978 with a maximum design heat input (fuel burn rate) of more than 250 mmBtu/hr (40 CFR 60 Subpart Da) establish limiting criteria for NO_x, SO_2, and particulate emissions only. No NSPS criteria have been established for limiting CO and VOC emissions. The heat input for each duct burner at the average ambient condition of 70 F is approximately 439 mmBtu/hr for this Project.

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, VOC, SO_2, and PM/PM_{10} in excess of the major source 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 (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.

3.2 Operations/Emissions Basis

As mentioned previously, the proposed operating scenario for the CTG/HRSGs with duct firing is 7,760 hours per year while firing natural gas. Moreover, the proposed operating scenario for firing fuel oil for each CTG is 1,000 hours per year. Table 3-1 shows the uncontrolled emission rates for natural gas operation of a GE PG7241(FA) combined cycle combustion turbine unit at 100 percent base load with duct burner firing (with and without power augmentation) and fuel oil firing at 100 percent of base load without duct burner at an average annual site temperature of 70 F. The emissions shown in Table 3-1 are controlled with dry low NO_x burners during natural gas firing and water injection during fuel oil firing and lb/mmBtu values are based on the higher heating value (HHV).

Table 3-1
Uncontrolled Emission Rates Per GE PG7241(FA) CCCT Unit

Emission Parameter	GE PG7241(FA) with Duct Firing (Natural Gas)[a]	GE PG7241(FA) with Power Augmentation and Duct Firing (Natural Gas)[b]	GE PG7241(FA) without Duct Firing (Fuel Oil)[c]
NO_x, ppmvd at 15% O_2	11.6	13.7	42.2
NO_x, lb/hr	92.1	114.4	311.0
NO_x, lb/mmBtu (HHV)	0.0420	0.0495	0.1628
CO, ppmvd at 15% O_2	18.1	26.3	14.3
CO, lb/hr	87.5	133.2	64.0
CO, lb/mmBtu (HHV)	0.0399	0.0576	0.0335
VOC, ppmvd at 15% O_2	3.6	6.3	2.7
VOC, lb/hr	9.8	18.2	7.0
VOC, lb/mmBtu (HHV)	0.0045	0.0079	0.0037
PM/PM_{10} (front half), lb/hr	11.2	11.4	17.0
PM/PM_{10} (front half), lb/mmBtu (HHV)	0.0051	0.0049	0.0089

Notes:

[a] Total emissions are based on 7,760 hours per year firing natural gas at 100 percent of base load with duct firing at an ambient temperature of 70 F.

[b] Total emissions are based on 1,000 hours per year firing natural gas at 100 percent of base load with power augmentation and duct firing at an ambient temperature of 70 F.

[c] Total emissions are based on 1,000 hours per year firing fuel oil at 100 percent of base load without duct firing at an ambient temperature of 70 F.

3.3 Economic Basis

Economic analysis used to determine the capital and annualized costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), "Top Down" Best Available Control Technology Guidance Document (March 1990), The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (February 1996, Fifth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

Table 3-2 lists the economic criteria used in the analysis of BACT alternatives. The contingency, real interest rate, economic life, labor cost, and reagent cost (anhydrous ammonia) were estimated based on guidance documents described above, internal project developer cost factors, and vendor budgetary estimates. The capital recovery factor was calculated based on the real interest rate and economic life of the equipment or the guaranteed catalyst life.

Table 3-2
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	20
Real Interest Rate, percent	7
Economic Life, years	15
Capital Recovery Factor, (15 years)	0.1098
Capital Recovery Factor, (3 years)	0.3811
Labor Cost, $/man-hr	40
Natural Gas Cost, $/mmBtu	3.07
Anhydrous Ammonia Cost, $/ton	269.25
Energy Cost, $/kWhr	0.0285
Catalyst Life Guarantee, years	3

4.0 Combustion Turbine NO_x and CO BACT Analysis

The objective of this analysis is to determine BACT for NO_x and CO emissions from the combined cycle combustion turbines. This includes the CTs and supplemental firing in the HRSG as a total unit during natural gas firing. The CTs without supplemental firing in the HRSG will only be considered when fuel oil firing. Unless otherwise noted the NO_x and CO emission rates described in this section are corrected to 15 percent oxygen.

4.1 NO_x BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Appendix A. A review of the BACT/LAER Clearinghouse documents (Florida DEP, 1997 – 2000, CAPCOA, 1985 - 2000; and USEPA, 1990 - 2000) indicates that the lowest emissions achieved for a natural gas fired combustion turbine is 2.0 ppmvd for the Federal Cold Storage Cogeneration facility located in California. The 2.0 ppmvd was achieved for six months (June 1997 to December 1997) with 15-minute continuous emission monitoring system (CEMS) averaging periods. Further, Region IX of the EPA has deemed the limit of 2.0 ppmvd at 15 percent oxygen was achieved in practiced with three hour averaging. The emissions from that unit are controlled through the use of water injection and a $SCONO_x$ system. It should be noted that the Federal Cold Storage Cogeneration facility is located in a non-attainment area for ozone, with NO_x regulated as a non-attainment pollutant. Thus, this emission level represents LAER for the CTG/HRSG. It should also be noted that this is a small, 222 mmBtu/hr GE model LM2500-M-2 combined cycle gas turbine that is only producing 32 MW (cogeneration). The current use of this specific control application on CTG/HRSG project applications (e.g., units under 30 MW) is not considered applicable to the Project as will be discussed.

In addition, the Sacramento Power Authority (Campbell Soup) located in the Sacramento Metropolitan AQMD in California has set a 3.0 ppmvd NO_x emission limit for a natural gas fired CTG/HRSG. The emissions from that unit are controlled through the use of standard combustors, water injection, and selective catalytic reduction (SCR). This unit consists of a 1,257 mmBtu/hr combined cycle natural gas fired Siemens V84.2 gas turbine generator with water injection for power augmentation and 200 mmBtu/hr of supplemental firing capacity producing 103 MW. This combustion turbine emission limit is noted in the Clearinghouse as being representative of LAER at the time of the permit (1994). Another stringent NO_x emissions limit for a gas fired CT is 3.5 ppmvd for the Brooklyn Navy Yard Cogeneration Project located in New York. The emissions from that unit are controlled through the use of dry low NO_x burners and SCR. Furthermore, a recent project listed in the CAPCOA BACT/LAER Clearinghouse database is the Sutter Power Plant in the Feather River AQMD in California. This unit has been permitted at 2.5 ppmvd at 15 percent O_2 for a one hour average. The facility will consist of two-combined cycle 1,900 mmBtu/hr gas fired, 170 MW Siemens Westinghouse 501FD turbines with 170 mmBtu/hr HRSGs driving a common 160 MW steam turbine. The NO_x emissions are to be controlled by dry low NO_x combustors, selective catalytic reduction, and low NO_x duct burners. The facility is listed in the CAPCOA BACT/LAER Clearinghouse documents, but is still under construction and demonstration of this level of NO_x control has not been achieved in practice at this time.

A review of the BACT/LAER Clearinghouse documents (Florida DEP, 1997 – 2000, CAPCOA, 1985 - 2000; and USEPA, 1990 - 2000) indicates that the lowest emissions for a fuel oil fired combustion turbine are 6.0 ppmvd for the Mantua Creek Generating facility and the Cogeneration Technology Linden facility, both located in New Jersey. The Mantua Creek Generating facility is permitted for three ABB GT-24 CCCTs with a total plant output of 881 MW. The emissions from that unit are controlled through the use of dry low NO_x and SCR. The Cogeneration Technology Linden facility is permitted for one GE 7FA CCCT with a total plant output of 180 MW. The emissions from this unit are controlled through the use of dry low NO_x and SCR. It should be noted that both projects also have a proposed NO_x emission limit of 2.5 ppmvd that represents LAER for the non-attainment locations of both projects. Both facilities are listed in the Florida DEP database, but demonstration of this level of NO_x control has not been achieved in practice at this time.

The EPA BACT/LAER Clearinghouse database lists two cogeneration facilities that have 10 ppmvd limits for NO_x emissions during fuel oil firing. The facilities are the Brooklyn Navy Yard Cogeneration Partnership located in New York, New York and the Newark Bay Cogeneration Project located in Newark, New Jersey. The control device at both facilities is SCR for each CCCT unit.

4.2 CO BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Appendix A. 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. The 617-mmBtu/hr combustion turbine units fire natural gas. The low emissions are achieved by reducing CO emissions by 80 percent (from 9 ppmvd to 1.8) through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in non-attainment areas for CO and ozone.

A further review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a fuel oil fired combustion turbine is 2.6 ppmvd at 15 percent O_2 for the Newark Bay Cogeneration L.P. project located in New Jersey. The 640-mmBtu/hr combustion turbine units fire kerosene. The CO emissions are achieved through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in non-attainment areas for CO and ozone.

4.3 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 NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x 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 oxide 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 NO_x 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 NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

In Combustor Type:

1) Water/Steam Injection
2) Dry Low-NO_x (DLN) Burners
3) Xonon

Post Combustion Type:

1) Selective Non-Catalytic Reduction (SNCR)
2) Selective Catalytic Reduction (SCR)
3) $SCONO_x$

4.3.1 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 that are formed as a result of incomplete combustion.

The development of DLN burners has replaced the use of wet controls except for certain cases such as oil firing. Therefore, the use of water injection will be considered for operations during oil firing and will be eliminated from further evaluation for control during natural gas firing for reducing NO_x emissions in this BACT analysis.

4.3.2 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 DLN burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called DLN 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 turbines.

DLN combustion turbine burner designs are available which use 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.

The controlled emission level will vary from manufacturer to manufacturer of the combustion turbine. The F-Class combustion turbines proposed for the Project are manufactured by GE and have DLN burners that can achieve a NO_x emission level of approximately 9 ppmvd at 15 percent O_2. It should also be noted that as with the standard combustor with water injection, the DLN burners could be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures will result in higher CO and VOC emissions.

Due to the proven performance of the DLN burner technology, this method of NO_x emissions control will be considered in this BACT analysis.

4.3.3 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 2,700 F at full power generation, which significantly reduces NO_x 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 Catalytica has with turbine manufacturers. To date, commercialization of this technology on large utility size combustion turbines such as proposed for the Project has not been developed.

Due to the technical and commercial limitations of this technology, this method of post-combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.3.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,500 to 1,900 F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions (slip). Operation above the temperature window results in increased NO_x emissions. The exhaust temperature at the exit of a combustion turbine, which is approximately 1,100 F for these units, is too low for any consideration of this technology.

Due to the technical and operational limitations on temperature and available reaction time, this method of post-combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.3.5 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CTG/HRSG projects for the past five 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, 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. Vanadium/titanium catalysts have been used on the vast majority of SCR system installations (greater than 95 percent). The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600 to 750 F. At temperatures above 800 F permanent damage to the vanadium/titanium catalyst occurs. For the combined cycle turbines proposed for the Project, this temperature window does exist. The flue gas temperature is reduced in the HRSG of the CTG/HRSG proposed for this Project and would typically range from 200 to 700 F. Accordingly, a vanadium/titanium catalyst can be installed at this Project. Therefore, the vanadium/titanium-based catalyst will be evaluated further for these units.

The operation of an SCR could present a negative impact on the environmental performance of the combustion turbine units. The environmental impact is due to the reaction of the excess ammonia that passes through the SCR with the sulfur trioxide (SO_3) in the flue gas to form ammonia-sulfur salts, such as ammonium bisulfate. These compounds form when the flue gas cools upon leaving the stack. This particulate adds to the emissions of PM_{10} from the unit.

Limitations to accurate measurements of emissions consistently below the 3 to 3.5 ppmvd are also a concern. Limitations in measuring any lower level of emission include sampling methods, analyzer limitations, and calibration gas error. Current EPA procedures and standards recognize such limitations. Currently, 40 CFR Part 75 allows emission monitors with span ranges of less than 200 ppmvd to have calibrations that deviate by up to 10 ppmvd and still be considered "in control." The difference of 1 ppmvd in the low values being measured will be in the "noise" range of the emission monitoring system. Lowering the limit to a level below 3.5 ppmvd will only magnify this lack of accuracy, thereby increasing the potential for emission exceedances without providing any further real reduction in emissions. A report by the American Society of Mechanical Engineers (ASME) on reviewing current measuring and monitoring practices indicated that relative accuracy results varied from 1.3 to 34 percent when testing at low NO_x emitters.

Because the SCR system requires the regulation of ammonia injection based on the emission monitors, the accuracy of the emission reading directly influences the amount of actual error in the ammonia injection rate. Therefore, erroneous emission readings can result in excess ammonia levels even when the actual NO_x values are below the permitted values. This may result in excessive ammonia "slip" being discharged to the atmosphere with little or no improvement in NO_x emissions. Reduction of the NO_x emission concentrations to levels below 3.5 ppmvd also raises concerns with the additional ammonia that may be emitted to obtain further reduced levels. Although SCR catalyst vendors have indicated that ammonia emissions will not be increased, these vendors are not solely responsible for guaranteeing ammonia slip. The distribution of the ammonia in the duct is the key parameter since localized maldistribution of the ammonia will cause the ammonia to pass through the catalyst without reacting with the NO_x. The proper distribution of the gas and ammonia is difficult to obtain when both reactants, NO_x and NH_3, are at such low concentrations. This distribution would be even more difficult, if not impossible, to maintain during transient operations, such as load changes, when flow patterns are changing. Changes in operation from one stable load to another stable load may present problems since the flow patterns and the loads may be different. Since the catalyst vendors are not responsible for the ammonia distribution, they typically limit their guarantees to some distribution level. Such conditions that increase ammonia emissions will be counter productive to the reduction of overall emissions since ammonia presents an emission problem itself and is a precursor to PM_{10}.

This method of post-combustion control will be considered in this BACT analysis to control NO_x emissions.

4.3.6 SCONOx

A third, relatively new post-combustion technology from Goal Line Environmental Technologies in conjunction with Alstom Power, is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. As previously noted, the South Coast Management District has declared LAER as 2.0 ppm of NO_x, based on this technology. Although this system has been proven on a small size unit, scale up concerns still exist with regard to the use of this technology on large units. To date, $SCONO_x$ has not been demonstrated in practice for a GE PG7241(FA) (i.e., Frame 7 or F-Class) combustion turbine.

The $SCONO_x$ system utilizes hydrogen (H_2) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO and thereby reducing plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300 to 700 F. Alstom/Goal Line guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst. This recycled material can account for as much as one-third the cost of the replacement catalyst.

The $SCONO_x$ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption $SCOSO_x$ catalyst. The $SCOSO_x$ catalyst is located upstream of the $SCONO_x$ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$ catalyst.

The $SCONO_x$ catalyst will require that it be re-coated or "washed" every six months to one year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the $SCOSO_x$ catalyst. The "washing" consists of removing the catalyst modules from the unit and placing each module with a potassium carbonate reagent, which is the active ingredient of the catalyst. The $SCOSO_x$ catalyst will also require washing, but due to limited operating experience with the $SCOSO_x$ catalyst, it is uncertain how often it will be required. However, it is expected that the $SCOSO_x$ catalyst will require annual washing.

The current $SCONO_x$ catalyst technology is in its second generation. The first generation operated for approximately ten months on a small LM-2500 combined cycle CT unit before it was taken out of service because of poor regeneration gas distribution.

A letter dated November 19, 1999 from EPA Region I had concerns regarding if $SCONO_x$ could handle the increased gas flow, mechanical durability and scale-up of the damper/louver system, reliability of the regenerative gas distribution system, the performance of the sulfur removal method, and catalyst performance guarantees. The EPA had concerns with the technical uncertainties and was apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. In addition there are issues with applying $SCONO_x$ to distillate fuel oil applications, given the higher sulfur content in the fuel. According to the EPA letter, Alstom Power has executed a re-design and testing program to develop the $SCONO_x$ system for large turbine applications, but to date this new re-designed system has not been demonstrated in practice.

The November 19, 1999 EPA letter addresses that Alstom Power had redesigned and fabricated a full-scale louver prototype system for larger turbine applications. In addition Alstom Power had cycled the prototype louver system 102,000 times (approximately 5 years of operation) at operating temperatures of 620 F and enclosed the system in a hot casing shell design to avoid thermal stresses from the heat recovery steam generator. Alstom Power has increased the catalyst module and regenerative gas distribution system that supplies gas to each individual module but, Alstom Power has only performed computational fluid dynamics (CFD) modeling to try and verify the gas regeneration system. Alstom Power has addressed degradation of the $SCONO_x$ catalyst from sulfur compounds found in natural gas, causing frequent system shutdowns, by verifying that a $SCOSO_x$ catalyst can be used upstream of the $SCONO_x$ catalyst. Furthermore, they claim the two catalysts are compatible and that the combined system will maintain sulfur and NO_x removal performance levels under different gas stream conditions. Alstom Power will provide performance guarantees to all owners and operators of natural gas fired combined cycle combustion turbines, regardless of size or O&M, and also will consider catalyst leasing arrangements where the responsibilty and rsik for catalyst maintenance will remain with Alstom. The EPA had them confirm the accuracy and correctness of their technical information in a response dated November 29, 1999. Alstom

Power has re-designed their $SCONO_x$ system for large turbine applications, but to date this new re-designed system has not been demonstrated in practice.

Another concern is the removal and replacement of the catalyst for re-coating without adversely impacting unit availability. The larger volume of catalyst used in an F class combustion turbine will require a significant period of washing or will necessitate the purchase of several spare catalyst modules.

The $SCONO_x$ system would also impact the power generation of the proposed facility. The flue gas pressure drop due to the catalyst is larger for the $SCONO_x$ process (approximately 4 to 5 in. w.g.) then an SCR process (approximately 2 to 3 in. w.g.). This increase in backpressure would result in an increase in lost power generation.

$SCONO_x$ is a technology that has effectively reduced emissions at the Federal Cold Storage facility thus far, and may have future promise. While mechanically very complicated, $SCONO_x$ technology allows for transient operation (load changes) and no ammonia issues are present, such as transportation, storage, or slip emissions. In addition, the wide operating temperature range has the potential for flexibility for future projects. The $SCONO_x$ catalyst can be placed in the most cost-effective location in an HRSG. The $SCONO_x$ catalyst can also significantly reduce CO emissions, thus reducing the need for an oxidation catalyst. However, there are a number of serious concerns regarding $SCONO_x$ that still need to be addressed prior to application to a Frame 7 or Class F machine. They include:

- Scale-up design issues for increasing the size of the application by 6 times from a LM-2500 to a Frame F combustion turbine. Scale-up design issues include damper size and proper distribution of regeneration gas.
- Mechanical system reliability: Damper and damper bearings are moving parts in the flue gas system that may present maintenance problems.
- On-line removal of catalyst for washing, including mechanics of how it is to be accomplished, time period, labor (cost), and safety issues.
- $SCOSO_x$ reliability: The SO_2 guard catalyst bed ($SCOSO_x$) can cause contaminated regeneration gas (containing sulfur and sulfur acids) to be handled, thereby questioning the effectiveness and reliability of the catalyst.
- Increased pressure drop.
- Proprietary Issue: $SCONO_x$ catalyst is a proprietary catalyst leading to concerns regarding long-term pricing.

- Warranty Issues: Since Goal Line is a relatively small company, there has been concern in the past regarding their ability to follow through with respect to potential warranty claims, not only for any single installation, but also in the event that multiple claims were to be made. Alstom Power has signed a licensing agreement which will provide the financial backing and credibility required for warranties and guarantees. Alstom Power has guaranteed the performance of their system, but operational risks associated with the use of $SCONO_x$ still need to be resolved.
- Financial Concerns: Lenders will have to assume performance and operational risks associated with the use of $SCONO_x$. The full-scope price without installation for a $SCONO_x$ system is estimated to be 4 times larger than installing an SCR system on a large scale combined cycle facility.

As discussed above, the $SCONO_x$ technology may have future promise. The application of this technology has been demonstrated on combined cycle CT units under 32 MW. Although, there are technical concerns with using this new technology related to the operating plant size proposed for the Project, this system will be evaluated in this BACT analysis.

4.4 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increase 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. The development of good combustion practice improvements with state of the art DLN burners has reduced CO emissions as compared to those previously obtained by the use of water injection as the main NO_x control method. These improved combustion characteristics have allowed minimization of CO emissions without sacrificing NO_x control performance. For this reason, the use of low NO_x burners that use good combustion practices is the standard method of also controlling CO emissions.

A current 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, dependent on the uncontrolled emission level, are capable of reducing CO emissions from 80 to 90 percent.

Another CO control technology that was screened was the previously discussed $SCONO_x$ process. The $SCONO_x$ system reduces CO emissions by oxidizing the CO to CO_2. As noted for the NO_x control evaluation, the $SCONO_x$ technology may have future promise. The application for this technology is currently limited to combined cycle CT units under 32 MW. The large size of the units proposed for this Project (170 MW) as compared to the size of the $SCONO_x$ operating plant makes the potential scale-up challenging and unpractical. Although, there are technical concerns with using this new technology related to the operating plant size proposed for the Project, this system will be evaluated in this BACT analysis.

This technology evaluation indicates that an oxidation catalyst and a $SCONO_x$ system are the control technologies suitable for further evaluation beyond the use of good combustion practices, as provided by a DLN burner.

4.5 Combined NO_x and CO Control Technology Summary

In-combustor NO_x and CO control by advanced combustion controls using dry low NO_x burners is the least stringent control technology considered for this Project. However, the use of an SCR system and oxidation catalyst or the $SCONO_x$ system to reduce emissions after combustion are technologies capable of achieving significantly lower emissions. Because the $SCONO_x$ system is capable of reducing NO_x and CO emissions, the NO_x and CO BACT analysis have been combined to avoid double counting the $SCONO_x$ technology, thus inflating its economic impacts. The following control technologies will be evaluated in this NO_x and CO BACT analysis and are ranked in order of relative control effectiveness:

- In-combustor NO_x and CO control consisting of DLN combustors to limit outlet emissions during natural gas and fuel oil firing for all operating loads for the CTG/HRSGs.
- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x to 3.5 ppmvd at 15 percent O_2 and CO to 3.6 ppmvd at 15 percent O_2 emissions from each combustion turbine with duct burner firing natural gas. The addition of an SCR system and oxidation catalyst to reduce outlet NO_x to 10 ppmvd at 15 percent O_2 and CO to 2.9 ppmvd at 15 percent O_2 emissions from each combustion turbine while firing fuel oil.

- The addition of a $SCONO_x$ system to reduce outlet NO_x emissions from each combustion turbine with duct burner firing natural gas and each combustion turbine firing fuel oil to 2.0 ppmvd at 15 percent O_2.

The SCR system with a 3.5-ppmvd NO_x emission limit and an oxidation catalyst will be compared to the $SCONO_x$ system with a 2.0 ppmvd NO_x emission limit.

The NO_x and CO emissions per CTG/HRSG unit with application of the above possible controls are summarized in Tables 4-1, 4-2, and 4-3 for natural gas (with and without power augmentation) and fuel oil firing, respectively.

Table 4-1
Estimated NO_x and CO Emissions
From Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing During Natural Gas Firing.

	Control Technology Alternatives		
	Dry Low NO_x Combustors	SCR/Oxidation Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	11.6	3.5	2.0
tons per year	311.4	94.0	53.7
percent reduction	N/A	70%	83%
NO_x BACT Analysis (Annual)[a] tons per year	311.4	94.0	53.7
CO Emissions			
ppmvd (at 15 percent O_2)	18.1	3.6	3.6
tons per year	295.8	59.2	59.2
percent reduction	N/A	80%	80%
CO BACT Analysis (Annual)[a] tons per year	295.8	59.2	59.2

Notes:

[a] Total emissions are based on 6,760 hours per year firing natural gas at 100 percent of base load with duct firing at an ambient temperature of 70 F.

Table 4-2
Estimated NO_x and CO Emissions
From Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing and Power Augmentation During Natural Gas Firing.

	Control Technology Alternatives		
	Dry Low NO_x Combustors	SCR/Oxidation Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	13.7	3.5	2.0
tons per year	57.2	14.6	8.4
percent reduction	N/A	74%	85%
NO_x BACT Analysis (Annual)[a] tons per year	57.2	14.6	8.4
CO Emissions			
ppmvd (at 15 percent O_2)	26.3	3.6	3.6
tons per year	66.6	9.2	9.2
percent reduction	N/A	86%	86%
CO BACT Analysis (Annual)[a] tons per year	66.6	9.2	9.2

Notes:

[a] Total emissions are based on 1,000 hours per year firing natural gas at 100 percent of base load with duct firing and power augmentation at an ambient temperature of 70 F.

Table 4-3
Estimated NO_x and CO Emissions From Alternate Combined Control Technologies Per GE 7FA CCCT During Fuel Oil Firing.

	Control Technology Alternatives		
	Dry Low NO_x Combustors	SCR/Oxidation Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	42.2	10	2.0
tons per year	155.5	36.9	7.4
percent reduction	N/A	76%	95%
NO_x BACT Analysis (Annual)[a] tons per year	155.5	36.9	7.4
CO Emissions			
ppmvd (at 15 percent O_2)	14.3	2.9	2.9
tons per year	32.0	6.4	6.4
percent reduction	N/A	80%	80%
CO BACT Analysis (Annual)[a] tons per year	32.0	6.4	6.4

Notes:

[a] Total emissions are based on 1,000 hours per year firing fuel oil at 100 percent of base load without duct firing at an ambient temperature of 70 F.

4.6 Evaluation of Feasible Technologies

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

4.6.1 $SCONO_x$ Energy Impacts

The use of a $SCONO_x$ system will increase the energy requirements on the system. The $SCONO_x$ system will increase the backpressure on each combustion turbine by about 4 inches water gauge (in. w.g.). This will reduce the output of each CTG/HRSG by approximately 0.3 percent and increase the lost power generation. In addition, the period required for catalyst washing will result in increasing the lost power generation. It is estimated the unit will be offline for a period of 4 days per year to accommodate the washing process. Furthermore, there will be an energy loss due to steam consumption from the regeneration system. The steam serving as a carrier gas for the natural gas will be required regardless of the $SCONO_x$ location in the HRSG. Alstom Power estimated that between 15,000 to 20,000 lb/hr of steam would be used in the regeneration production. These three effects will be added together to determine the total lost power generation and are included in the annualized cost estimate. The $SCONO_x$ system will have minimal effect on power consumption that will be necessary to operate the damper actuators and regeneration system. Alstom Power estimated that approximately 10 to 20 kW would be consumed during operation of the $SCONO_x$ system. This increase in power consumption will be included in the annualized cost estimate. The natural gas required for the production of the regeneration gas will increase the annualized cost associated with using the $SCONO_x$ system. Alstom Power estimated that 2 percent of the carrier gas will consist of the regeneration gas. Therefore, approximately 7,000 ft^3/hr (300 lb/hr) will be consumed in the regeneration process of the $SCONO_x$/$SCOSO_x$ catalyst. The annualized cost of natural gas consumption is included in the annualized cost analysis.

4.6.2 $SCONO_x$ Environmental Impacts

The $SCONO_x$ catalyst is composed of precious metals coated with potassium carbonate. When the potassium carbonate coating can no longer be regenerated, the precious metal content of the remaining catalyst can be recycled. The oxidation of CO also directly results in increased production of CO_2, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO_2 because of its contribution to global climate change. Installation of a $SCONO_x$ system would directly counter this initiative.

4.6.3 SCR 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 ammonia reagent for injection. In addition, an SCR system catalyst will increase the backpressure on each combustion turbine. The SCR system will add about 1.6 inches water gauge (in. w.g.) backpressure to each unit. This will reduce the output of the each unit by approximately 0.1

percent. Increased power consumption and lost power generation are included in the annualized cost estimate.

4.6.4 SCR Environmental Impacts

The vanadium content of the SCR catalyst may contribute to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. Because of this, recycling of SCR catalysts for vanadium has become common.

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. According to Committee on Toxicology of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

Human Response	Concentration (ppm)
Immediate throat irritation	Equal to or greater than 400
Eye irritation	Equal to or greater than 700
Coughing	Equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

Some ammonia slip from the HRSG stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. 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. With fresh catalyst ammonia slip emissions will be very low, but as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and may be classified as hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

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 SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 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.

4.6.5 Oxidation Catalyst Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine. The additional backpressure of about 1.2 inches, water gauge, will reduce the combustion turbine output by approximately 0.1 percent. The cost of lost power revenue due to the backpressure is included in the economic analysis.

4.6.6 Oxidation Catalyst Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions is that a 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 approximately 30 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 combustion turbine outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. The increase in H_2SO_4 emissions would increase PM_{10} (matter less than 10 microns in diameter) emissions.

Spent oxidation catalyst is made up of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of the precious metal content of the catalyst, the CO oxidation catalyst can also be recycled to recover the precious metals.

As mentioned previously, the installation of an oxidation catalyst will also increase the backpressure on the turbine, thereby decreasing efficiency. This decrease in efficiency will lead to increased emissions of all pollutants on a unit power output basis. The oxidation of CO also directly results in increased production of CO_2, a greenhouse gas.

There is currently a worldwide effort to reduce industrial emissions of CO_2 because of its contribution to global climate change. Installation of an oxidation catalyst would directly counter this initiative.

4.6.7 Economic Impacts for SCR/Oxidation Catalyst and SCONOx

The use of an SCR and oxidation catalyst has significant economic impacts 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 each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year and at 100 percent of base load with power augmentation and duct firing for 1,000 hours per year on natural gas. The BACT costs presented in this analysis also include operating the combustion turbine for 1,000 hours per year on fuel oil. The capital and annualized cost for the $SCONO_x$ system also includes the $SCOSO_x$ system.

4.6.7.1 Capital Costs for SCR/Oxidation Catalyst and SCONOx

Table 4-4 presents the capital costs for installing an SCR/Oxidation Catalyst and $SCONO_x$ system on each CTG/HRSG unit during natural gas and fuel oil firing. The cost of the SCR/Oxidation Catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation, and freight. The cost of the $SCONO_x$ system includes the catalyst, regenerative gas distribution system, catalytic reactor housing, controls and instrumentation, and freight. The balance of plant equipment cost for $SCONO_x$ was estimated to be the same percentage as an SCR/Oxidation Catalyst system. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the SCR and oxidation catalyst material were based on vanadium/titanium and precious metal type catalysts, respectively. The direct installation costs included the balance of plant items listed in Table 4-4 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs for the SCR/Oxidation Catalyst system are percentages of the purchased equipment costs (PEC) and are site specific. The indirect costs for the $SCONO_x$ system are percentages of the $SCONO_x$ system capital cost and are site specific. It should be noted that the OAQPS Control Cost Manual recommends the indirect costs are to be calculated by multiplying by the PEC, however, for the $SCONO_x$ system this is judged to be inaccurate. The PEC for using $SCONO_x$ would overestimate the indirect costs associated for the project; therefore, the indirect costs were estimated by multiplying the percentages by only the $SCONO_x$ system cost. In addition, the 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

Total capital costs for the SCR and oxidation catalyst control system is calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per combustion turbine unit for a 3.5 ppmvd NO_x and 3.6 ppmvd CO outlet emission during natural gas firing and a 10 ppmvd NO_x and 2.9 ppmvd CO outlet emission during fuel oil firing SCR/Oxidation Catalyst system is estimated to be $3,286,000.

The total capital costs for the $SCONO_x$ control system is also calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per combustion turbine unit for a 2.0 ppmvd NO_x and 3.6 ppmvd CO outlet emission during natural gas firing and a 2.0 ppmvd NO_x and 2.9 ppmvd CO outlet emission during fuel oil firing using a $SCONO_x$ system is estimated to be $14,131,000.

Table 4-4

Combined NO_x and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit

	$SCONO_x$ System	SCR/Oxidation Catalyst	Low NO_x Burners	Remarks
Direct Capital Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3
SCR and Oxidation Catalysts System	Included	1,907,000	N/A	Estimated from Engelhard Corporation
$SCONO_x$ Catalyst	7,800,000	N/A	N/A	Estimated from ABB Alstom Power
$SCONO_x$ System	5,200,000	N/A	N/A	Estimated from ABB Alstom Power
Catalyst Reactor Housing	Included	268,000	N/A	Estimated from ABB Alstom and scaled from an estimate from Engelhard Corporation
Control/Instrumentation	Included	180,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Equipment/Storage)	N/A	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	13,000,000	2,555,000	N/A	
Freight	650,000	128,000	N/A	5% of Purchased Equipment Costs
Total Purchased Equipment Costs	13,650,000	2,683,000	N/A	
Direct Installation Costs				
Balance of Plant	4,095,000	805,000	N/A	For SCR & $SCONO_x$: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	**9,945,000**	**1,998,000**	Base	Catalyst cost is excluded as annual O&M cost
Indirect Capital Costs				
Contingency	2,730,000	537,000	N/A	20% of Total Purchased Equipment Costs (TPEC)
Engineering and Supervision	520,000	268,000	N/A	For $SCONO_X$: 10% of $SCONO_X$ System Cost; For SCR: 10% of TPEC
Construction & Field Expense	260,000	134,000	N/A	For $SCONO_X$: 5% of $SCONO_X$ System Cost; For SCR: 5% of TPEC
Construction Fee	520,000	268,000	N/A	For $SCONO_X$: 10% of $SCONO_X$ System Cost; For SCR: 10% of TPEC
Start-up Assistance	104,000	54,000	N/A	For $SCONO_X$: 2% of $SCONO_X$ System Cost; For SCR: 2% of TPEC
Performance Test	52,000	27,000	N/A	For $SCONO_X$: 1% of $SCONO_X$ System Cost; For SCR: 1% of TPEC
Total Indirect Capital Costs	4,186,000	1,288,000	Base	
Total Installed Cost	**14,131,000**	**3,286,000**	Base	

4.6.7.2 *Operating Costs for SCR/Oxidation Catalyst and SCONOx*

Table 4-5 presents the annualized operating costs and emission rates using a SCR/Oxidation catalyst and $SCONO_x$ system during natural gas and fuel oil firing. Annualized operating costs for the SCR/Oxidation Catalyst include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. Throughout the life of the plant, catalyst elements for both the SCR and the oxidation catalyst will require periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions will increase and the catalyst will eventually have to be replaced. The oxidation catalyst is installed upstream of the ammonia injection grid and SCR catalyst, therefore there are no problems associated with ammonia slip, but the CO catalyst will degrade such that CO emissions increase. Currently, catalyst manufacturers are willing to guarantee an SCR and oxidation catalyst life of three years of equivalent operating hours. The catalyst replacement cost was calculated by multiplying the cost of the catalyst replacement modules by 15 percent for installation cost, 5 percent that includes freight, and a capital recovery factor based on the real interest rate over the 3 year guaranteed life of the catalyst.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.4 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with NO_2. The heat rate penalty cost item reflects the cost due to the SCR and oxidation catalyst backpressure losses. The additional backpressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annualized cost estimate.

The annualized operating costs for the $SCONO_x$ system include catalyst replacement, energy impacts, operating personnel, maintenance, natural gas consumption, catalyst washing, and heat rate penalty due to backpressure losses and steam usage. The $SCONO_x$ catalyst will require periodic washing and replacement throughout the life of the facility. The emissions will increase as the catalyst becomes deactivated, resulting in more frequent washing cycles. Replacement of the catalyst will result in lost power generation during the outage period. Alstom Power estimates the anticipated life of the first 10 percent of the catalyst to be 10 years and the remaining catalyst to be 30 years. However, Alstom Power is only willing to guarantee a $SCONO_x$ catalyst life for 3 years. Therefore, the guaranteed life will be used to determine the catalyst replacement cost.

Table 4-5
Combined NO_x and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit

	$SCONO_x$ System	SCR/Oxidation Catalyst	Low NO_x Burners	Remarks
Direct Annual Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	3,589,000	686,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	197,000	40,000	N/A	See text for background information on this item
Reagent Feed	N/A	87,000	N/A	Assumes 1.4 stoichiometric ratio
Natural Gas Consumption	191,000	N/A	N/A	Based on 7,000 ft^3/hr required
Power Consumption	4,000	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR and damper actuation for $SCONO_x$
Lost Power Generation				
$SCONO_x$ Washing	694,000	N/A	N/A	Down time due to $SCONO_x$ washing period
Steam Consumption	655,000	N/A	N/A	Loss based on 15,000 lb/hr of steam required
Backpressure	132,000	95,000	N/A	Includes backpressure on CT
Annual Distribution Check	N/A	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	5,462,000	923,000	N/A	
Indirect Annual Costs				
Overhead	56,000	20,000	N/A	60% of O&M Labor
Administrative Charges	283,000	66,000	N/A	2% of Total Installed Cost
Property Taxes	389,000	90,000	N/A	2.75% of Total Installed Cost
Insurance	141,000	33,000	N/A	1% of Total Installed Cost
Capital Recovery	1,552,000	151,000	N/A	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	2,421,000	360,000	N/A	
Total Annualized Cost	**7,883,000**	**1,283,000**	N/A	
Annual Emissions, tpy	144.1	220.1	918.5	Total emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	774.3	698.3	N/A	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, $/ton	**10,200**	**1,800**	N/A	Total Annualized Cost/Emissions Reduction
Incremental Annualized Cost	**6,600,000**	N/A	N/A	See text for background information on this item
Incremental Reduction	**87,000**	N/A	N/A	See text for background information on this item.

The use of either an SCR/Oxidation Catalyst system or a $SCONO_x$ system increases the energy requirements of the project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the project. $SCONO_x$ consumes a relatively small amount of power to open and close the catalyst dampers and to produce the regenerating gas. Maintenance costs will consist of routine system maintenance for each system. However, there is an additional maintenance cost associated with catalyst washing for the $SCONO_x$ system. The replacement materials are assumed to be two percent of the original cost for equipment and labor is assumed to be equal to materials. The $SCONO_x$ system will include the additional O&M cost for catalyst washing.

4.6.7.3 Total Annualized Costs for SCR/Oxidation Catalyst and SCONOx

Total annualized costs for the SCR and oxidation catalyst control systems are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. Table 4-5 shows the total annualized cost per unit for a SCR/Oxidation Catalyst system per combustion turbine is estimated to be $1,283,000. This annualized cost for the CTG/HRSG unit results in a cost effectiveness of approximately $1,800 per ton of NO_x and CO removed.

The total annualized costs for the $SCONO_x$ control system are calculated as the sum of the operating costs plus capital recovery factor times the total installed costs. The total annualized cost per unit for a $SCONO_x$ system per combustion turbine is estimated to be $7,883,000. This annualized cost for the CTG/HRSG unit results in a cost effectiveness of approximately $10,200 per ton of NO_x and CO removed.

The incremental annualized cost system is calculated as the difference in annualized cost between the $SCONO_x$ and SCR/Oxidation catalyst. In addition, the incremental NO_x and CO reduction in tons per year is calculated as the difference in combined tons per year of NO_x and CO removed (alternative controlled baseline) between the two control technologies. Furthermore, the incremental removal cost is determined by dividing the incremental annualized cost by the controlled baseline reduction. It should be noted that this incremental cost effectiveness is considered relative to the next most stringent control alternative baseline (i.e., $SCONO_x$ compared to SCR/Oxidation Catalyst rather than just DLN). These cost increments will allow a comparison between the two removal technologies. The incremental annualized cost between $SCONO_x$ and the SCR/Oxidation Catalyst system is estimated to be \$6,600,000. This results in an incremental cost effectiveness of approximately \$87,000. This cost is considered high and for this application it is not cost effective to use $SCONO_x$ over a SCR/Oxidation catalyst system per CTG/HRSG unit.

4.7 Economic Impacts for SCR

The control of NO_x emissions separate from CO emission control is possible through the application of an SCR to the CTG/HRSG units without additional CO emission controls. To determine the BACT levels for NO_x controls without the influence of the CO emissions a separate economic analysis is required. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year while firing natural gas and operating at 100 percent of base load for 1,000 hours per year with power augmentation and duct firing on natural gas. The BACT costs presented in this analysis also include operating each combustion turbine at 100 percent of base load for 1,000 hours per year on fuel oil.

4.7.1 Capital Costs for SCR System

Table 4-6 presents the capital costs for installing an SCR system on the CTG/HRSG units during natural gas and fuel oil firing to achieve a NO_x outlet emission level of 3.5 and 10.0 ppmvd. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation and freight. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the SCR catalyst material were based on vanadium/titanium type catalysts. The direct installation costs included the balance of plant items listed in Table 4-6 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the PEC and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

Total capital costs for the SCR system to reduce NO_x is calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. the total capital cost per unit for an SCR catalyst system per combustion turbine is estimated to be $2,480,000.

Table 4-6
NO_x Control Capital Cost Per GE 7FA CTG/HRSG Unit

Cost Item	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
SCR Catalysts System	1,161,000	N/A	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	N/A	Scaled from an estimate from Engelhard Corporation
Control/Instrumentation	140,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia Injection/Dilution Equipment	Included	N/A	Estimated from Engelhard Corporation
Ammonia Storage	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	1,769,000	N/A	
Freight	88,000	N/A	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,857,000	N/A	
Direct Installation Costs			
Balance of Plant	557,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	1,588,000	Base	Catalyst Cost is excluded as annual O&M Cost
Indirect Capital Costs			
Contingency	371,000	N/A	20% of Total Purchased Equipment Cost
Engineering and Supervision	186,000	N/A	10% of Total Purchased Equipment Cost
Construction & Field Expense	93,000	N/A	5% of Total Purchased Equipment Cost
Construction Fee	186,000	N/A	10% of Total Purchased Equipment Cost
Start-up Assistance	37,000	N/A	2% of Total Purchased Equipment Cost
Performance Test	19,000	N/A	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	892,000	Base	
Total Installed Cost	**2,480,000**	Base	

4.7.2 Operating Costs for SCR

Table 4-7 presents the annualized operating costs and emission rates using an SCR during natural gas and fuel oil firing. Annualized operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. The description of the operating costs and effects of ammonia consumption, backpressure, and catalyst life have already been described in Section 4.6.

4.7.3 Total Annualized Costs for SCR

The total annualized costs for the SCR system are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. The total annualized cost per unit for an SCR system per combustion turbine is estimated to be $1,003,000. This annualized cost for each CTG/HRSG unit results in an incremental cost effectiveness of approximately $2,600 per ton of NO_x removed.

Table 4-7
NO_x Control Annualized Cost Per GE 7FA CTG/HRSG Unit

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	380,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	36,000	N/A	See text for background information on this item
Reagent Feed	87,000	N/A	Assumes 1.4 stoichiometric ratio
Power Consumption	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR
Lost Power Generation	53,000		Back Pressure on CT
Annual Distribution Check	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	571,000	N/A	
Indirect Annual Costs			
Overhead	17,000	N/A	60% of O&M Labor
Administrative Charges	50,000	N/A	2% of Total Installed Cost
Property Taxes	68,000	N/A	2.75% of Total Installed Cost
Insurance	25,000	N/A	1% of Total Installed Cost
Capital Recovery	272,000	N/A	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	432,000	N/A	
Total Annualized Cost	**1,003,000**	N/A	
Annual Emissions, tpy	145.4	524.1	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	378.7	N/A	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, $/ton	**2,600**	N/A	Total Annualized Cost/Emissions Reduction

4.8 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts 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 each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year without power augmentation and 1,000 hours per year with power augmentation on natural gas. The BACT costs presented in this analysis also include operating each combustion turbine for 1,000 hours per year on fuel oil.

4.8.1 Capital Cost for Oxidation Catalyst

Table 4-8 presents the capital costs for installing an oxidation catalyst on the CTG/HRSG units during natural gas and fuel oil firing to achieve a CO outlet emission level of 3.6 and 2.9 ppmvd, respectively. The capital costs for the systems includes the oxidation catalyst reactor, controls and instrumentation and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the balance of plant items listed in Table 4-8 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the PEC and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

Total capital costs for the oxidation catalyst control system to reduce CO is calculated as the sum of the direct and indirect installed costs. The total capital cost per unit for an oxidation catalyst system is estimated to be $1,306,000.

4.8.2 Operating Costs for Oxidation Catalyst

Table 4-9 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve an 80 and 86 percent reduction in CO emissions while firing natural gas for the CTG/HRSG units with and without power augmentation, respectively. CO outlet emissions would be reduced to a maximum of 3.6 and 2.9 ppmvd during natural gas and fuel oil firing respectively, for the CTG/HRSG units. Annualized operating costs for the system includes 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 an oxidation catalyst life of three years of equivalent operating hours for an oxidation catalyst.

4.8.3 Total Annualized Costs for Oxidation Catalyst

Total annualized costs for using the oxidation catalyst are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. The total annualized cost per combustion turbine unit is estimated to be $570,000. This annualized cost per CTG/HRSG unit results in a cost effectiveness of approximately $1,800 per ton of CO removed.

Table 4-8

CO Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst	746,000	NA	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	NA	Scaled from an estimate from Engelhard Corporation based on catalyst size
Control/Instrumentation	40,000	NA	Estimated
Purchased Equipment Costs	1,054,000		
Freight	53,000		5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000		
Direct Installation Costs			
Balance of Plant	332,000	NA	8% For Foundations & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting.
Total Direct Capital Cost Less Catalyst	775,000	Base	
Indirect Capital Costs			
Contingency	221,000	NA	20% of Total Purchased Equipment Cost
Engineering and Supervision	111,000	NA	10% of Total Purchased Equipment Cost
Construction & Field Expense	55,000	NA	5% of Total Purchased Equipment Cost
Construction Fee	111,000	NA	10% of Total Purchased Equipment Cost
Start-up Assistance	22,000	NA	2% of Total Purchased Equipment Cost
Performance Test	11,000	NA	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	531,000	Base	
Total Installed Cost	**1,306,000**	Base	

Table 4-9

CO Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	306,000	NA	Catalyst life of 3 yr. Of equivalent operating hours
Operation and Maintenance	4,000	NA	See text for background information on this item
Lost Power Generation	40,000	NA	Back Pressure on Combustion Turbine
Total Direct Annual Cost	350,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	26,000	NA	2% of Total Installed Cost
Property Taxes	36,000	NA	2.75% of Total Installed Cost
Insurance	13,000	NA	1% of Total Installed Cost
Capital Recovery	143,000	NA	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	220,000	NA	
Total Annualized Cost	**570,000**	NA	
Annual Emissions, tpy	74.7	394.4	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	319.7	NA	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, $/ton	**1,800**	NA	Total Annualized Cost/Emissions Reduction

4.9 Conclusions

To summarize the information discussed in this section of the NO_x and CO BACT, there are several significant technological concerns with utilizing the $SCONO_x$ system. First, $SCONO_x$ is still in the development and demonstration stage. Even though Alstom Power has re-designed their $SCONO_x$ system for large turbine applications, to date this new re-designed system has not been demonstrated in practice. The LAER level of 2 ppmvd NO_x emissions based on using a combination of water injection and a $SCONO_x$ catalyst is considered unproven and technically unacceptable for this project. Although, that system was proven successful for operation at 32 MW, the plant size proposed for the Project raises technical concerns with using this new technology. Second, the higher capital and annualized O&M cost of the $SCONO_x$ system will negatively impact the Project's economics. The capital cost for a $SCONO_x$ system would be approximately $14,131,000 per CTG/HRSG unit. Furthermore, installation of a $SCONO_x$ system designed to reduce NO_x and CO emissions would add approximately $7,883,000 to the annualized operating cost per CTG/HRSG unit. The resultant cost effectiveness is approximately $10,200 per ton of NO_x and CO removed for each CTG/HRSG unit. These costs are considered high for reducing NO_x and CO emissions for this Project compared to an equivalent SCR and oxidation catalyst system.

The annualized and capital costs for the SCONOx system are approximately 4 and 5 times the cost for an equivalent SCR and oxidation catalyst system. The capital cost for an SCR/Oxidation catalyst system would be about $3,286,000 per CTG/HRSG unit. Installation of a SCR/Oxidation catalyst system would add approximately $1,283,000 to the annualized operating cost of each CTG/HRSG unit. The resultant cost effectiveness is approximately $1,800 per ton of NO_x and CO removed per CTG/HRSG unit. Furthermore, the incremental annualized cost of the $SCONO_x$ system compared to the SCR/Oxidation catalyst system is about $6,600,000 for each CTG/HRSG unit, which is considered high in light of the existing feasible technologies that can attain the same reductions at a lower overall cost. The $SCONO_x$ system at its current capital and annualized cost can not compete economically to a SCR/Oxidation catalyst system for this combustion turbine application. Therefore, based on economics and the lack of a demonstrated emission limit on larger CTG/HRSG units, this new system was not considered BACT for the Project.

SCR catalysts have proven emissions reduction capabilities and low maintenance requirements at a variety of different facilities throughout the United States, Europe, and Asia. SCR systems are representative of the BACT/LAER level of NO_x emissions reduction. SCR systems have been successfully used on combined cycle combustion turbine applications. The capital and annualized operating cost for an SCR system per CTG/HRSG unit is $2,480,000 and $1,003,000, respectively. The incremental cost effectiveness for the CTG/HRSG unit is estimated to be $2,600 per additional ton of NO_x removed. The operation of an SCR at lower emission rates will likely result in increased PM_{10} emissions caused by the additional SO_2 to SO_3 oxidation, as well as associated ammonium bisulfate/sulfate and H_2SO_4 emissions. Therefore, based on energy, environmental and economic impacts, the use of DLN combustors with an SCR to meet an emissions level of 3.5 ppmvd for each natural gas fired CTG/HRSG with duct burners (with and without power augmentation) and 10 ppmvd for each combustion turbine during fuel oil firing are proposed as BACT for NO_x.

Installation of an oxidation catalyst would have negative energy, environmental and economic impacts. In summary, the oxidation catalyst would increase the backpressure on the turbine; thereby increasing emissions per unit of electric generation due to decreased turbine efficiency and increased fuel consumption. The oxidation catalyst would increase particulate emissions as a result of increased SO_3 production. In addition, the oxidation catalyst results in an increase in CO_2 emissions, which may contribute to global warming. The negative economic impacts include increased production costs due to decreased efficiency, increased capital cost for the installation of the oxidation catalyst, and increased operating cost due to periodic replacement of the oxidation catalyst.

The capital cost to install an oxidation catalyst system for a CTG/HRSG unit designed to reduce CO emissions by 80 and 86 percent would be $1,306,000 and the annualized operating cost would be increased by $570,000 per year. The resultant cost effectiveness on a per ton of CO removed basis is approximately $1,800. Therefore, based on economic, environmental, and energy impacts, the proposed CO BACT for the control of CO emissions from each combustion turbine during natural gas firing is good combustion practices to achieve a CO emission limit of 18.1 ppmvd at 15 percent O_2 (without power augmentation) and 26.3 ppmvd at 15 percent O_2 (with power augmentation). The proposed CO BACT for the control of CO emissions from each combustion turbine is good combustion practices to achieve a CO emission limit of 14.3 ppmvd at 15 percent O_2 during fuel oil firing.

5.0 Combustion Turbine PM/PM_{10} BACT Analysis

The objective of this analysis is to determine BACT for PM/PM_{10} emissions from the combined cycle combustion turbines. This includes the combustion turbines and supplemental firing in the HRSG as a total unit.

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 a particulate emission limit. 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 referenced by the State of Florida, such as the FPL Fort Myers, Santa Rosa and Tallahassee projects, the use of combustion controls is considered BACT for particulate matter and is proposed for this project. BACT was determined to be good combustion controls during natural gas and fuel oil firing.

6.0 Combustion Turbine VOC BACT Analysis

The objective of this analysis is to determine BACT for VOC emissions from the combustion turbines while firing natural gas and fuel oil. This includes duct burner firing with natural gas and only CT firing with fuel oil. Unless otherwise noted the VOC emission rates described in this section are corrected to 15 percent oxygen.

6.1 BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Appendix A. A review of the EPA BACT/LAER Clearinghouse Bulletin Board and the California Air Resource Board (BACT/LAER) indicates that the most stringent VOC emissions limit for a gas fired CT (454 mmBtu/hr, 48 MW) is 0.6 ppmvd at 15 percent O_2 for Bear Mountain Limited located in California. The CAPCOA and EPA BACT/LAER Clearinghouse databases also list a VOC limit of 1.0 ppmvd at 15 percent O_2 for the Casco Ray Energy Company in Maine, Florida Power and Light facility in Florida, and the Sutter Power Plant located California. The emission levels at the Florida Power and Light facility and the Sutter Power Plant are achieved through the application of good combustion practices and an oxidation catalyst. The Casco Ray Energy Company controls VOC emissions with DLN burners.

6.2 Alternative VOC Emission Reduction Systems

Volatile organic compounds are formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. VOC are typically defined as non-methane, non-ethane hydrocarbons that are emitted from the combustion turbine and duct burner. VOC 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 VOC 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 VOC emissions.

An alternative control method is catalytic oxidation, which is a post-combustion method for reduction of VOC emissions. This process is identical to that used for CO reduction where the same oxidation catalyst is used to promote the oxidation of VOC to

CO_2 and H_2O. The oxidation catalyst is typically a precious metal catalyst. No reagent injection is necessary.

Two factors affect the ability of the catalyst to promote oxidation of VOC. Those factors are the temperature of the flue gas as it passes through the catalyst and the species of VOC present in the flue gas. Higher temperatures promote better oxidation of VOC. Long chain hydrocarbons are also easier to oxidize than short chain hydrocarbons. Therefore, the ability of the catalyst to oxidize VOC depends directly on the specific hydrocarbons that are in the flue gas.

Since the exact nature of the VOC's to be emitted from a combustion source are difficult to determine, the exact reduction that may be achieved can not be easily quantified. This uncertainty and the limited amount of removal that may be expected are reflected in the permitting of past projects with oxidation catalyst. As previously noted, most of the oxidation catalyst applications identified in the BACT/LAER databases indicate only an assumed destruction rate varying from 5 to 10 percent. This assumed rate is most likely a reflection that the catalyst was justified as a CO control technology for the given application. Any reduction of VOC was assumed since the catalyst was not installed based on VOC reduction. The estimated VOC emissions for the units with the applicable control technology are listed in Tables 6-1 and 6-2 per CTG/HRSG unit.

6.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenarios evaluated. Although several facilities in the CAPCOA BACT/LAER database have listed 5 to 10 percent reductions in VOCs using an oxidation catalyst, this VOC BACT conservatively assumed a 10 percent (without power augmentation) and 50 percent (with power augmentation) reduction during natural gas firing. A 30 percent reduction in VOC emissions was estimated during fuel oil firing.

6.3.1 Economic Impacts

The use of an oxidation catalyst has a significant negative economic impact to the project. Analysis of the economic impacts is provided in the following section. The VOC BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year on natural gas without power augmentation and 1,000 hours per year with power augmentation on natural gas. The VOC BACT costs presented in this analysis also are based on operating each combustion turbine for 1,000 hours per year on fuel oil.

Table 6-1
Estimated VOC Emissions From Alternate Control Technologies Per GE 7FA CTG/HRSG Unit During Natural Gas Firing

	Dry Low NO_x Combustors (without Power Augmentation)	Oxidation Catalyst	Dry Low NO_x Combustors (with Power Augmentation)	Oxidation Catalyst
VOC Emissions				
ppmvd at 15 percent O_2	3.6	3.2	6.3	3.2
tons per year	33.2[a]	29.9[a]	9.1[b]	4.6[b]
percent removal	N/A	10	N/A	50

Notes:

[a] Annual emission based on 7,760 hours of natural gas operation per year at 100 percent of base load with duct firing at an ambient temperature of 70 F.

[b] Annual emission based on 1,000 hours of natural gas operation per year at 100 percent of base load with power augmentation and duct firing at an ambient temperature of 70 F.

Table 6-2 Estimated VOC Emissions From Alternate Control Technologies Per GE 7FA CTG/HRSG Unit During Fuel Oil Firing		
	Dry Low NO_X Combustors	Oxidation Catalyst
VOC Emissions		
ppmvd at 15 percent O_2	2.7	1.9
tons per year	3.5[b]	2.5[b]
Percent removal	N/A	30

Notes:

[a] Annual emission based on 1,000 hours of fuel oil operation per year at 100 percent of base load without duct firing at an ambient temperature of 70 F.

6.3.1.1 Capital Costs

Table 6-3 presents the capital costs for installing an oxidation catalyst system on the combined cycle combustion turbines proposed for the Project. The capital costs for the systems includes the oxidation catalytic reactor, controls and instrumentation and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the balance of plant items listed in Table 6-3 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the PEC and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

6.3.1.2 Operating Costs

Table 6-4 presents the annualized operating costs and emission rates using an oxidation catalyst for the reduction of VOCs per CTG/HRSG unit during natural gas and fuel oil firing. VOC outlet emissions would be reduced to a maximum of approximately 3.2 and 1.9 ppmvd during natural gas and fuel oil firing, respectively, for each CTG/HRSG unit. Annualized operating costs for the system includes 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.

6.3.1.3 Total Annualized Costs

Total annualized cost for the oxidation catalyst system is calculated as the sum of the annualized operating costs plus capital recovery. The total annualized operating cost for an oxidation catalyst is estimated to be $570,000 per CTG/HRSG unit, which results in an incremental VOC removal cost of approximately $64,000 per ton.

6.3.2 Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine. The additional backpressure of 1.2 inches, water gauge, will reduce the combustion turbine output by approximately 0.1 percent. The cost of the lost power revenue due to the backpressure is included in the economic analysis.

Table 6-3 VOC Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst	746,000	NA	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	NA	Scaled from an estimate from Engelhard Corporation based on catalyst size
Control/Instrumentation	40,000	NA	Estimated; includes controls and monitoring equipment
Purchased Equipment Costs	1,054,000	NA	
Freight	53,000	NA	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000	NA	
Direct Installation Costs			
Balance of Plant	332,000	NA	8% For Foundations & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting.
Total Direct Capital Cost Less Catalyst	775,000	Base	
Indirect Capital Costs			
Contingency	221,000	NA	20% of Total Purchased Equipment Cost
Engineering and Supervision	111,000	NA	10% of Total Purchased Equipment Cost
Construction & Field Expense	55,000	NA	5% of Total Purchased Equipment Cost
Construction Fee	111,000	NA	10% of Total Purchased Equipment Cost
Start-up Assistance	22,000	NA	2% of Total Purchased Equipment Cost
Performance Test	11,000	NA	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	531,000	Base	
Total Installed Cost	**1,306,000**	Base	

Table 6-4 VOC Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Tables 6-1 and 6-2
Catalyst Replacement	306,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	4,000	NA	See text for background information on this item
Lost Power Generation	40,000	NA	Back pressure on combustion turbine
Total Direct Annual Cost	350,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	26,000	NA	2% of Total Installed Cost
Property Taxes	36,000	NA	2.75% of Total Installed Cost
Insurance	13,000	NA	1% of Total Installed Cost
Capital Recovery	143,000	NA	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	220,000	NA	
Total Annualized Cost	**570,000**	NA	
Annual Emissions, tpy	36.9	45.8	Emissions taken from Tables 6-1 and 6-2 (Combined Natural Gas and Fuel Oil)
Emissions Reduction, tpy	8.9	NA	Emissions calculated from Tables 6-1 and 6-2
Total Cost Effectiveness, $/ton	**64,000**	NA	Total Annualized Cost/Emissions Reduction

6.3.3 Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce VOC emissions is that a 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 approximately 30 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the VOC oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. The increase in H_2SO_4 emissions would increase PM_{10} (particulate matter less than 10 microns in diameter) emissions.

6.4 Conclusions

Installation of an oxidation catalyst system designed to reduce VOC emissions would add approximately $570,000 to the annualized cost and the capital cost is approximately $1,306,000 per CTG/HRSG unit. This corresponds to a cost effectiveness on a per ton of VOC removed basis of approximately $64,000 for each CTG/HRSG unit. This is considered a high cost and VOC catalysts have not typically been applied to similar CTG/HRSG applications under BACT consideration. Therefore, based on economic, environmental, and energy impacts, the proposed BACT for the control of VOC emissions from each combustion turbine during natural gas firing is good combustion practices using advanced combustion controls design to achieve an emission level of 3.6 ppmvd at 15 percent O_2 (without power augmentation) and 6.3 ppmvd at 15 percent O_2 (with power augmentation). The proposed BACT for the control of VOC emissions from each combustion turbine during fuel oil firing is good combustion practices using advanced combustion controls design to achieve an emission level of2.7 ppmvd at 15 percent O_2.

7.0 Combustion Turbine SO_2 BACT Analysis

The objective of this analysis is to determine BACT for sulfur dioxide (SO_2) emissions from the combustion turbine. This includes the combustion turbine and supplemental firing in the HRSG as a total unit. The SO_2 emissions are based on operating each combustion turbine with duct firing at 100 percent of base load for a total of 7,760 hours per year on natural gas and operating each combustion turbine for a total of 1,000 hours per year on fuel oil.

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. Fuel oil will be limited to less than 0.05 percent sulfur. The selection of these fuels provides inherently low SO_2 emissions. No supplemental SO_2 emission controls have been imposed on natural gas fired combustion turbines by regulatory agencies.

Emissions of SO_2 can be controlled by limiting sulfur content in the fuel, limiting high sulfur fuel usage, or by a post-combustion flue gas desulfurization (FGD) system. The fuel for this project is natural gas with a sulfur content of 0.5 grains per 100 standard cubic feet. Therefore, it is considered to have the BACT for this project to be using natural gas and low sulfur fuel oil.

8.0 Cooling Tower BACT Analysis

Uncontrolled cooling towers can be high emitters of PM/PM_{10} under certain conditions. PM/PM_{10} from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as drift. A portion of the water droplets emitted from the tower exhausts will evaporate leaving the suspended or dissolved solids in the atmosphere and thus subject to dispersion. Typically, drift eliminators are used to minimize drift (droplet) losses. The drift eliminator control efficiency for the proposed cooling tower is 0.002 percent. The use of drift eliminators are proposed as BACT for PM/PM_{10} for the cooling tower.

9.0 Conclusions

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for OUC. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. The proposed operating scenario for the combustion turbines consists of operating up to 7,760 hours per year while firing natural gas and operating up to 1,000 hours per year while firing fuel oil. Although, as with most combustion turbine facilities that have been permitted in the United States, the use of fuel oil will be considered as a backup fuel to natural gas for this project and the balance of the facility's operation is expected to consist of firing natural gas. For the purposes of this analysis, worst case annual operation and emissions were evaluated. This is equivalent to natural gas operation at 6,670 hours per year at full load with duct firing, natural gas firing at full load for 1,000 hours per year at full load with duct firing and power augmentation, and fuel oil firing at full load for 1,000 hours per year.

GE PG7241(FA) CTG/HRSG Units:

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

- Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O_2.
- Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O_2.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O_2 (without power augmentation) and 26.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O_2 during fuel oil firing.

Particulate (PM/PM_{10}) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O_2 (without power augmentation) and 6.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O_2 during fuel oil firing.

Sulfur Dioxide (SO_2) emissions – BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

APPENDIX A

Table A-1 NO_x BACT Clearinghouse Review List						
Facility	**State**	**Permit Date**	**Process**	**Output**	**Emission limit, ppmvd**	**Control Technology**
Federal Cold Storage Cogeneration	CA	Dec-96	GE LM2500-M-2	222 mmBtu/hr	2.0	Water Injection, SCONOx
Sutter Power Plant	CA	APR-99	SW 501F	170 MW	2.5	Dry low NOx, SCR
La Paloma Generating Co.LLC	CA	MAY-99	ABB Model GT-24	262 MW	2.5	Dry-low NOx, SCR
Turlock Irrigation District	CA	AUG-94	GE LM5000	417 mmBtu/hr	3.0	SCR, Steam Injection
Sacramento Power Authority (Campbell Soup)	CA	AUG-94	Siemens V84.2	1257 mmBtu/hr	3.0	Water injection, SCR
Brooklyn Navy Yard Cogeneration Partners L.P.	NY	JUN-95	Turbine, Natural Gas Fired	240 MW	3.5	SCR
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas	170 MW	3.5	SCR
Granite Road Limited	CA	MAY-91	Turbine, Gas	460.9 mmBtu/hr	3.5	SCR, Steam Injection

Table A-2 CO BACT Clearinghouse Review List						
Facility	**State**	**Permit Date**	**Process**	**Output, MW**	**Emission limit ppmvd**	**Control Technology**
Newark Bay Cogeneration Partnership, L.P.	NJ	JUN-93	Turbines, Combustion Natural Gas Fired	617	1.8 ppmvd	Oxidation Catalyst
Saranac Energy Company	NY	JUL-92	Turbines, Combustion Natural Gas Fired	1123	3 ppmvd	Oxidation Catalyst
Alabama Power, Plant Barry	AL	AUG-98	GE 7FA	170	0.057 lb/mmBtu	Good Combustion Control
Alabama Power, Plant Barry	AL	AUG-99	GE 7FA	170	0.06 lb/mmBtu	Good Combustion Control
Mobile Energy, LLC - Hog Bayou	AL	JAN-99	GE 7FA	170	0.04 lb/mmBtu	Good Combustion Control
Sutter Power Plant	CA	APR-99	Turbine, SW 501F	170	4 ppmvd	Oxidation Catalyst
Alabama Power Theodore Cogeneration Facility	AL	MAR-99	GE 7FA	170	0.086 lb/mmBtu	No Control
Blue Mountain Power, L.P	PA	JUL-96	Combustion Turbine with Heat Recovery Boiler	153	3.1 ppmvd	Oxidation Catalyst
Brooklyn Navy Yard Cogeneration Partners, L.P	NY	JUN-95	Turbine, Natural Gas Fired	240	4 ppmvd	No Control
Crockett Cogeneration (C&H Sugar)	CA	OCT-93	GE PG7221 (FA)	240	5.9 ppmvd	Good Combustion Control

Table A-3 VOC BACT Clearinghouse Review List						
Facility	**State**	**Permit Date**	**Process**	**Output, MW**	**Emission limit**	**Control Technology**
Bear Mountain Limited	CA	AUG-94	Turbine, GE, Cogeneration, 48 MW	48	0.6 ppmvd	Oxidation Catalyst
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas, two	170	1.0 ppmvd	Low NOx Burner
Florida Power and Light	FL	MAR-91	Turbine, Gas, 4 Each	240	1.0 ppmvd	Combustion Control
Sutter Power Plant	CA	APR-99	SW 501F, Combined Cycle	170	1.0 ppmvd	Oxidation Catalyst
Florida Power and Light	FL	JUN-91	Turbine, Gas, 4 Each	400	1.6 ppmvd	Combustion Control
Sacramento Cogeneration Authority	CA	AUG-94	GE LM6000	42	1.1 lb/hr	Oxidation Catalyst
Carson Energy Group and Central Valley Financing	CA	JUL-93	GE LM6000	42	2.46 lb/hr	Oxidation Catalyst

Attachment 5
Air Modeling Protocols

Air Modeling Protocol

Class II

BLACK & VEATCH

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P.O. Box 8405
Kansas City, Missouri 64114 USA

Tel: (913) 458-2000

Black & Veatch Corporation

OUC/KUA/FMPA
Stanton 3/ Cane Island 4
Pre-Application Meeting

B&V Project 098362.0040
B&V File 14.0400
June 7, 2000

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32339

Subject: PSD Air Quality Impact Analyses

Attention: Cleve Holladay

As discussed at the meeting at FDEP's offices on May 31, 2000, OUC, KUA, FMPA propose to construct and operate either a 3X1 at Stanton EC, 2X1 at Stanton EC, and/or a 2X1 at Cane Island. The combustion turbines will all be "F" class machines operating in combined cycle (CC) mode, with all projects reserving the ability to operate in simple cycle (SC) mode. Fuels will consist of natural gas with No. 2 distillate fuel oil as backup. Each proposed project will constitute a major modification to an existing major source, with expected significant emissions of NO_x, CO, SO_2, and PM_{10}. As such, a BACT analysis, air quality impact analyses, and additional impact analyses will be required for those pollutants as part of the PSD review process. The information contained in the Attachment of this letter, as discussed in the meeting on May 31, 2000, will serve as the modeling protocol for the three proposed projects and thus a formal protocol document will not be required for the PSD air quality impact anlysis. Please review the information and provide comments by Monday, June 19, 2000. Additionally, a list of items which FDEP agreed to review and provide additional information has also been included.

If you have questions, please feel free to contact me at 913-458-9062 or Mr. Brian O'Neal at 913-458-8199.

Very truly yours,

BLACK & VEATCH

Kyle J. Lucas
Air Quality Scientist

bdo

cc: File
M. Soltys
M. Rollins
B. O'Neal
K. Butler

Attachment

PSD Air Quality Impact Analysis

- Latest version of ISCST3 will be used with regulatory defaults.
- Simple terrain with the FLAT option.
- Five years of meteorological data (1987 – 1991 Orlando surface with Tampa upper air).
- Due to the large number of operating scenarios, an enveloping approach to obtain the worst-case operating scenario for use in the air dispersion modeling can be used.
- Downwash Analysis
  The Building Profile Input Program (BPIP) will be used to assess downwash for all stacks. Furthermore, it was suggested that for the Stanton facility, the future coal units be considered in the downwash analysis of the proposed project to prevent potential downwash issues in the future for this turbine addition if the coal units are built. However, inclusion of the future coal addition is not required.
- The same type of receptor grid used for KUA3 can be used for the proposed projects. Specifically, a 10 km nested rectangular grid consisting of 100 m spacing out to 1 km, 500 m spacing from 1 to 5 km, 1 km spacing from 5 to 10 km, and 100 m spacing along the fenceline.
- Rural dispersion coefficient.
- FDEP did not require state specific modeling be performed.
- If the proposed projects impacts are less than the PSD SILs, then demonstration is complete. A NAAQS and Increment analysis will be performed only if the project(s) impacts are above the PSD SILs. If such analyses are necessary, FDEP will provide the source inventories.
- A request for a waiver from pre-application monitoring, if required, can be requested in the application. A separate letter is not necessary.
- All PM is considered to be PM_{10} and is for front-half catch only (filterable).

Class I Area Analyses

- The Chassahowitzka Wilderness Area is a PSD Class I area located approximately 100 km from the proposed projects and must be modeled using the Calpuff air dispersion model to assess criteria pollutant impacts, regional haze, and pollutant deposition analyses.
- FDEP uses 4 percent of the Class I Increment to represent the Class I SILs for criteria pollutant impacts modeling.
- Calpuff Lite modeling is acceptable for the regional haze analysis as long as the project is under the 5 percent threshold. If the Calpuff Lite analysis yields results greater than 5 percent level, a Calpuff refined analysis must be performed.

- Use Calpuff default ozone and ammonia levels. A protocol for the refined analysis, if applicable, should be prepared and submitted to Cleve Holladay. FDEP will organize all Class I analyses and activities with the Fish and Wildlife Service.
- A deposition analysis is required.

112(g)- case-by-case MACT

- The analysis will consist of the MACT determination for HAPS. If the Potential to Emit case for the facility is below the 25 tpy limit and the 10 tpy limit for each individual pollutant, then no further analysis is required.
- AP-42 is an acceptable reference.

Additional Information from FDEP

- Cleve Holladay will assess whether the electronic files (specifically the Calmet file(s)) from the submitted Calpine Osprey Project can be used for the proposed projects.
- Cleve Holladay will verify if the deposition analysis for the Chassahowitzka Class I area is to be a total nitrogen analysis or a nitrates analysis.
- Jeff Koerner will verify which combustion sources are applicable to the MACT determination.

Air Modeling Protocol
Class I

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

OUC/KUA/FMPA
Stanton 3

B&V Project 098362.0040
B&V File 14.0400
August 30, 2000

Florida Department of Air Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399

Subject: Class I Analyses Protocol Document

Attention: Cleve Holladay

As discussed at the meeting at FDEP's offices on May 31, 2000, OUC, KUA, and FMPA propose to construct and operate a 2-on-1 combined cycle electric generating plant at the Stanton Energy Center. As such, FDEP requested additional impact analyses be performed, in addition to the PSD air quality impact analysis, for the Chassahowitzka Wilderness Area which is a designated Class I area and under the jurisdiction of the US Fish and Wildlife Service (FWS) as the Federal Land Manager (FLM). Enclosed, please find the class I analyses modeling protocol document for your review as discussed in the meeting on May 31, 2000. Please review the document and provide you comments by Friday, September 8, 2000.

If you have any questions, please feel free to contact me at 913-458-9062 or Mr. Brian O'Neal at 913-458-8199.

Very truly yours,

BLACK & VEATCH

Kyle J. Lucas
Air Quality Specialist

kjl
Enclosure

cc: File
M. Soltys
M. Rollins
B. O'Neal

STANTON ENERGY CENTER
CALPUFF MODELING PROTOCOL

PREPARED BY
BLACK & VEATCH

AUGUST 2000

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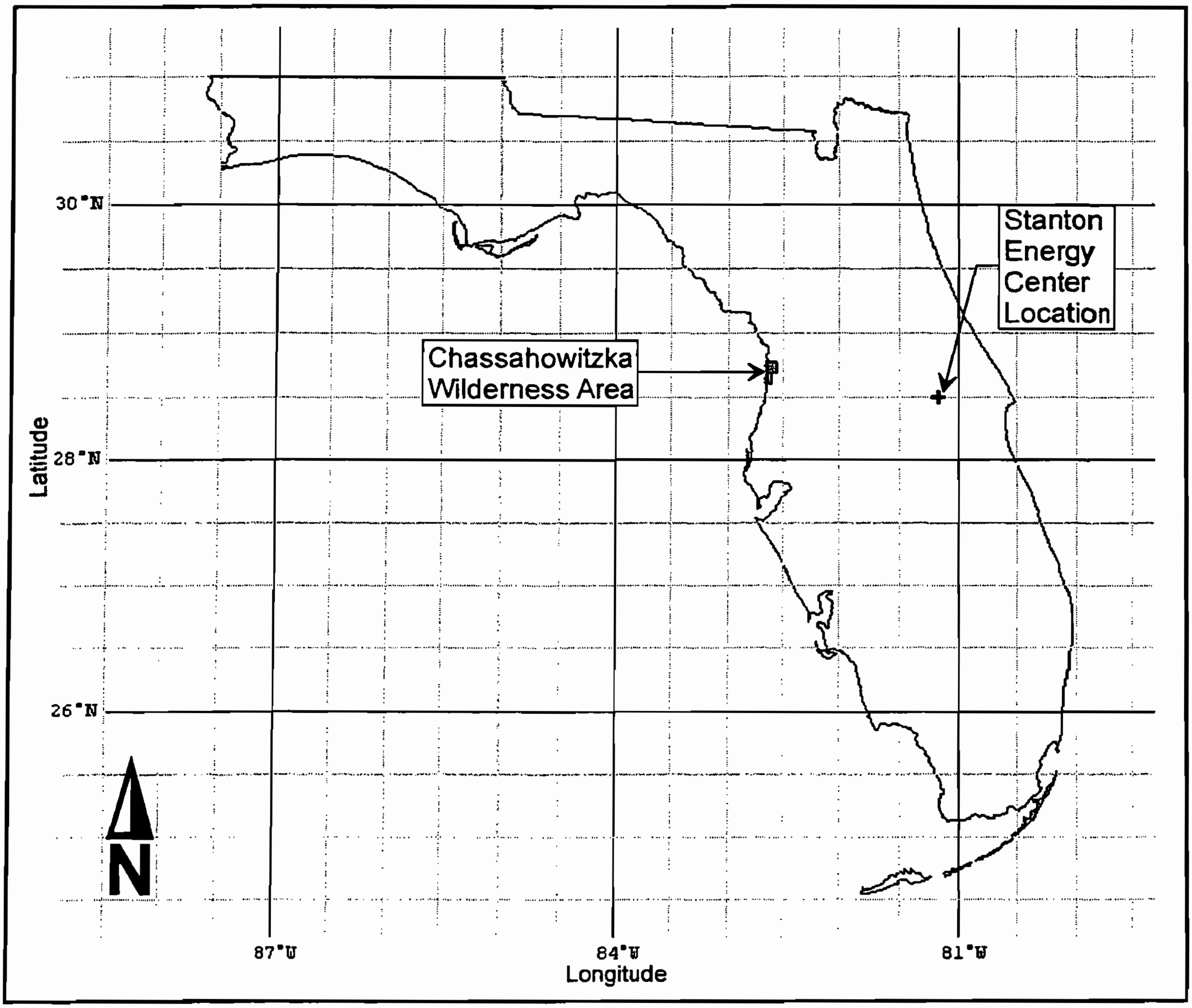
Chassahowitzka Receptor Locations

1.0 Introduction

Orlando Utilities Commission (OUC), in conjunction with Kissimmee Utility Authority (KUA) and Florida Municipal Power Authority (FMPA), are proposing to construct two 170-MW combined-cycle combustion turbines serving one steam turbine (2x1), for a total nominal output of approximately 620 MW, at the existing Stanton Energy Center, which is located near the city of Orlando, Florida. As part of the air impact evaluation for the proposed facility, the Florida Department of Environmental Projection (FDEP) has requested that analyses of the proposed facility's affect on the Chassahowitzka Wilderness Area (CWA) be performed. The CWA is a Prevention of Significant Deterioration (PSD) Class I area located in west-central Florida approximately 100 km northwest of the proposed facility site. Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze, deposition, and Class I Significant Impact Levels (SILs). Figure 1-1 presents the locations of the proposed project site with respect to the CWA.

The CALPUFF analysis will closely follow those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Draft Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) dated October 1999, as well as coordination with the FDEP who will in turn communicate as necessary with the U.S. Fish and Wildlife Service (FWS) which is the Federal Land Manager (FLM) for the CWA. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach.



Location of Stanton Energy Center And Chassahowitzka Wilderness Area

Figure 1-1

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, version 5.4) air modeling system will be used to model the proposed facility and assess the AQRVs at CWA. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts. Both CALMET and CALPUFF will be used in a manner that is recommended by the IWAQM Phase 2 Report and Draft Phase I FLAG Report.

2.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 2-1 will be used for the modeling analyses.

2.3 Building Wake Effects

The CALPUFF analysis will include the proposed facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures will be processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

Table 2-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM10
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour SO_4, NO_3 and PM10 concentrations for the year. Deposition: Highest predicted annual SO_2, SO_4, NO_x, HNO_3, and NO_3 values in deposition units. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Ozone: 80 ppb; Ammonia: 10 ppb

2.4 Receptor Locations

The CALPUFF analysis will use an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the CWA. Specifically, the array will consist of receptors obtained from FDEP via a July 20, 2000 email, which covers the extent of the CWA. A graphical depiction of the receptor locations can be found in the Attachment. Because the terrain throughout the CWA is flat, an elevation of zero will be used for all receptors.

2.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.2) will be used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data to be used and processed in the CALMET model.

2.5.1 CALMET Settings

The CALMET settings, including horizontal and vertical grid coverage, number of weather stations (surface, upper air, and precipitation), and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed facility to the receptors at the CWA with at least a 50-km buffer zone in each direction. The air modeling analysis will be performed in the UTM coordinate system.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets, prognostic wind fields or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for a one-year data base set; specifically, 1990. The analysis will use the MM4 mesoscale meteorological data set to initialize the CALMET wind field. The data will be extracted from a 12-volume CD-ROM set put out by the National Climatic Data Center (NCDC). The MM4 data have a horizontal spacing or resolution of 80 km and are used to simulate atmospheric variables within the modeling domain.

The mesoscale meteorological data set (MM4) to be used in CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables will be processed into the appropriate format and introduced into the CALMET model through the utilization of additional data files obtained from numerous sources. These ancillary data files are described in more detail in the following sections.

2.5.4 Surface Data Stations and Processing

The surface station data for the CALPUFF analyses will consist of data from several National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The station data may be obtained directly from NCDC or extracted from a CD-ROM set put out by NCDC. The data will be processed with the CALMET preprocessor utility program, SMERGE, to create one surface file.

2.5.5 Upper Air Data Stations and Processing

The analysis will include several upper air NWS stations located within the CALMET domain. Data for these stations will be obtained from the NCDC Radiosonde Data CD and processed into the NCDC Tape Deck (TD) 6201 format by the READ62 utility program for input to CALMET.

2.5.6 Precipitation Data Stations and Processing

Precipitation data will be processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations within the CALMET domain. The precipitation files are contained in a 2-volume CD-ROM set from NCDC. The utility programs PXTRACT and PMERGE will be used to process the data into the format for the Precip.dat file that is used by CALMET.

2.5.7 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain will be obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data will be extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, will also be obtained from the USGS. Land-use values for the domain grid will be extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters will be combined with the terrain information in a processor called MAKEGEO. This processor will produce one GEO.DAT file for input to CALMET.

2.6 Facility Emissions

Performance data for the combustion turbines will be based on vendor data at certain design ambient temperatures at base load operation, considering both natural gas and distillate fuel oil firing. The maximum pound per hour emission rates considering representative ambient temperatures at base load operation for natural gas and distillate fuel oil firing will be used for the pollutants modeled with CALPUFF.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the CWA, including regional haze, deposition (both sulfur and nitrogen), and Class I SILs.

3.1 Regional Haze Analysis

Regional haze analyses will be performed for the CWA for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

3.1.1 Visibility

Visibility is an AQRV for the CWA. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the CWA lies beyond 50 km from the proposed facility, the change in visibility is analyzed as regional haze at those locations of the CWA. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

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, 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.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} 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_{extb}, or; percent change in extinction. Based on National Park Service (NPS) guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extsb}) \times 100$$

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual range for the CWA will be obtained from the Draft Phase I FLAG document. The average relative humidity factor for each species' worst day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity will be obtained by using Table 2.A-1 of Appendix 2.A of the Draft Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). Again, all of this can be accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis will follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98). Table 3-1 summarizes the IWAQM Phase II

Table 3-1 Outline of IWAQM Refined Modeling Analyses Recommendations*	
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage. A figure depicting the location of the receptors can be found in the Attachment.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO_4, PM10 and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction. This can all now be accomplished with the use of the CALPOST post-processor.
**IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).	

recommendations. The methodology below will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of six modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. A typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain maximum 24-hour SO_4 and NO_3 impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

   $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4

   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375

   Convert the NO_3 impact to NH_4NO_3 by the following formula:

   NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3

   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   b_{exts} = 3 x NH_4NO_3 x f(RH) + 3 x $(NH_4)_2SO_4$ x f(RH) + 1 x PM_{10}
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FALG document with the following formula:

   b_{extb} = 3.912 / Visual range (km)
5. Compute the change in extinction coefficients:

   in terms of deciviews:

   $dv = 10 \ln (1 + b_{exts} / b_{extb})$

   in terms of percent change of visibility:

   $\Delta\% = (b_{exts} / b_{extsb}) \times 100$

Based on the predicted SO_4, NO_3, and PM10 concentrations, the proposed facility's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2 Deposition Analyses

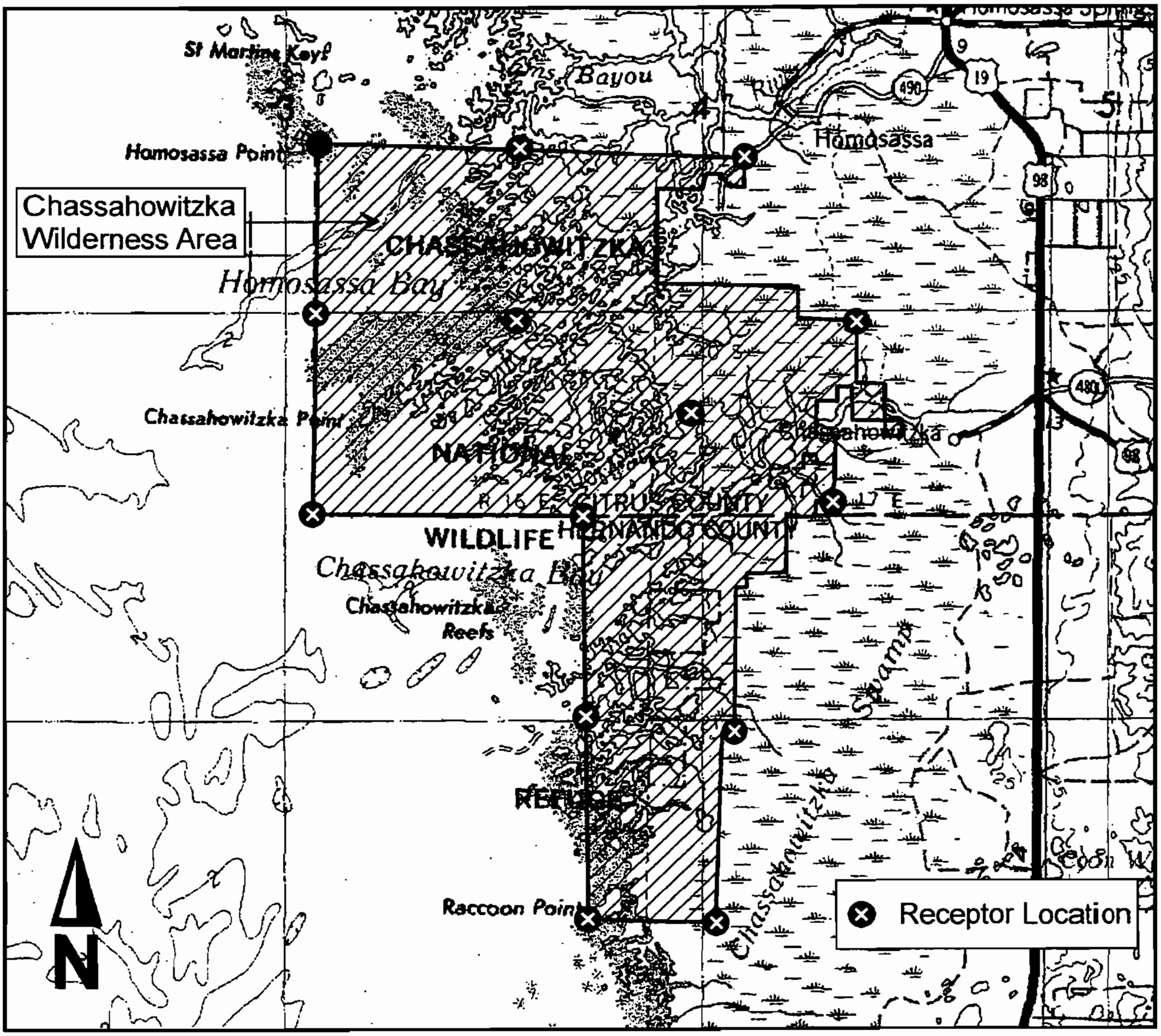
Deposition analyses will be performed for the CWA for both sulfur and nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 3.1 (including output of both dry and wet deposition).
2. Perform individual CALPOST post-processor runs to output the maximum annual average wet and dry deposition impacts of SO_2, SO_4, NO_x, HNO_3, and NO_3 in $g/m^2/s$ units.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the above CALPOST runs to account for normalization based on the ratio of molecular weights, as well as the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results will be in kg/ha/yr.
4. For total sulfur deposition, sum the results of both the wet deposition and dry deposition values for both SO_2 and SO_4.
5. For total nitrogen deposition, sum the results of both the wet deposition and dry deposition values for NO_x, HNO_3, and NO_3.

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) onto to the CWA will be calculated for the criteria pollutants that exceed PSD Significant Emission Levels (SELs) for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values

ATTACHMENT



Chassahowitzka Wilderness Area Receptors

Attachment 1

Chassahowitzka.srf

Attachment 6
Air Dispersion Modeling Files

Appendix 10.7

Air Construction Application Forms
for the
Curtis H. Stanton Energy Center
Combined Cycle
Combustion Turbine Project

Submitted by

Orlando Utilities Commission
Kissimmee Utility Authority
Florida Municipal Power Authority
and
Southern Company-Florida, LLC

Prepared by
Black & Veatch

January 2001
Project No. 98362

Contents

Attachments

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Authority, and Southern Company – Florida, LLC.	
2. Site Name: Curtis H. Stanton Energy Center	
3. Facility Identification Number: 564	[ ] Unknown
4. Facility Location: Orlando Utilities Commission (OUC) Curtis H. Stanton Energy Center Street Address or Other Locator: 5100 South Alafaya Trail City: Orlando County: Orange Zip Code: 32831	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: James O. Vick; Manager, Environmental Affairs
2. Application Contact Mailing Address: Organization/Firm: Southern Company – Florida, LLC Street Address: One Energy Place City: Pensacola State: Florida Zip Code: 32520-0328
3. Application Contact Telephone Numbers: Telephone: (850)444-6311 Fax: (850)444-6217

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	0950137 - 001 - AC
3. PSD Number (if applicable):	PSD - FL - 313
4. Siting Number (if applicable):	PA 81-14 SA2

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:______________________________

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

Current construction permit number:______________________________

Operation permit number to be revised:______________________________

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

Operation permit number to be revised/corrected:______________________________

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

Operation permit number to be revised:______________________________

Reason for revision:______________________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Robert G. Moore, Vice-President of Power Generation and Transmission
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Street Address: One Energy Place City: Pensacola State: FL Zip Code: 32520-0328
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (850) 444 - 6383 Fax: (850) 444 - 6744
4. Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [X], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Robert G. Moore 1/14/2001 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: ~~Greg N. Terry~~ Registration Number: ~~52786~~
2. Professional Engineer Mailing Address: Organization/Firm: Street Address: ~~One Energy Place~~ City: ~~Pensacola~~ State: ~~FL~~ Zip Code: ~~32520-0340~~
3. Professional Engineer Telephone Numbers: Telephone: ~~(850) 429 - 2381~~ Fax: ~~(850) 429 - 2246~~

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   Robert G. Moore; Vice-President of Power Generation and Transmission

2. Owner/Authorized Representative or Responsible Official Mailing Address:
   Organization/Firm: Southern Company – Florida, LLC
   Street Address: One Energy Place
   City: Pensacola State: Florida Zip Code: 32520-0328

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: (850)444-6383 Fax: (850)444-6744

4. Owner/Authorized Representative or Responsible Official Statement:

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

   ______________________________ ______________________

   Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Rodney I. Unruh
   Registration Number: Florida No. 28564

2. Professional Engineer Mailing Address:
   Organization/Firm: Black & Veatch
   Street Address: 11401 Lamar
   City: Overland Park State: Kansas Zip Code: 66211

3. Professional Engineer Telephone Numbers:
   Telephone: (913)458-7309 Fax: (913)458-2934

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature ______________________ Date 01/17/01

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
004	Nominal 317 MW Combined Cycle Combustion Turbine	AC1A	N/A
005	Nominal 317 MW Combined Cycle Combustion Turbine	AC1A	N/A
006	Cooling Tower	AC1A	N/A
007	Distillate Fuel Oil Storage Tank (1,680,000 gal)		N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $____________________ [X] Not Applicable (Part of the site Certification Fee).

Construction/Modification Information

1. Description of Proposed Project or Alterations: The electric generating facility to be installed for at the existing Curtis H. Stanton Energy Center will include the construction of two combined cycle combustion turbine (CCCT) units rated at approximately a nominal 317 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a backup fuel, and one 10-cell mechanical draft cooling tower. Each CCCT will be equipped with a heat recovery steam generator (HRSG) containing natural gas-fired duct burners. The two CCCT/HRSGs will feed a single, common steam turbine generator; this configuration is regularly referred to as a 2x1 configuration. The CCCTs will include provisions for the optional use of evaporative coolers and steam power augmentation. The new CCCT/HRSGs will be capable of operating at base load for up to 8,760 hours per year with a potential of 1,000 hours of operation using steam injection for power augmentation and 1,000 hours of operation on distillate fuel oil.
2. Projected or Actual Date of Commencement of Construction: 10/01/2001
3. Projected Date of Completion of Construction: 9/01/2003

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone:17	East (km):483.61	North (km):3151.1	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 28/29/17		Longitude (DD/MM/SS): 81/10/03	
3. Governmental Facility Code: 4	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters): Construction of two new combustion turbines, one cooling tower and one distillate oil fuel storage tank at an existing facility.			

Facility Contact

1. Name and Title of Facility Contact: James O. Vick; Manager, Environmental Affairs		
2. Facility Contact Mailing Address: Organization/Firm: Southern Company – Florida, LLC Street Address: One Energy Place City: Pensacola	State: Florida	Zip Code: 32520-0328
3. Facility Contact Telephone Numbers: Telephone: (850) 444-6311	Fax: (850) 444-6217	

B. FACILITY REGULATIONS

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): Facility units currently exempt under NESHAPs. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used--the cooling tower is not a major source of HAPS.	

List of Applicable Regulations

See Attachment A

C. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NO_x	A	N/A	N/A		
CO	A	N/A	N/A		
PM/PM_{10}	A	N/A	N/A		
SO_2	A	N/A	N/A		
VOC	A	N/A	N/A		
HAPS	B	N/A	N/A		

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID:Attachment B [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID:Attachment C [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID:Attachement D [ ] Not Applicable [ ] Waiver Requested
4.	Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID:SCA Section 4.5[ ] Not Applicable [ ] Waiver Requested
5.	Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
6.	Supplemental Information for Construction Permit Application: [X] Attached, Document ID: SCA Appendix 10.7________ [ ] Not Applicable
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities:
   [ ] Attached, Document ID:________ [X] Not Applicable

9. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID:________
   [ ] Equipment/Activities On site but Not Required to be Individually Listed
   [X] Not Applicable

10. Alternative Methods of Operation:
   [ ] Attached, Document ID:________ [X] Not Applicable

11. Alternative Modes of Operation (Emissions Trading):
   [ ] Attached, Document ID:________ [X] Not Applicable

12. Identification of Additional Applicable Requirements:
   [ ] Attached, Document ID:________ [X] Not Applicable

13. Risk Management Plan Verification:
   [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________)
   [ ] Plan to be submitted to CEPPO (Date required:____________________________)
   [X] Not Applicable

14. Compliance Report and Plan:
   [ ] Attached, Document ID:________ [X] Not Applicable

15. Compliance Certification (Hard-copy Required):
   [ ] Attached, Document ID:________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

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

Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator operating in combined cycle (CCCT) mode with one heat recovery steam generator (HRSG) having a nominal rating of 317 MW. The CCCT/HRSG will be capable of firing both natural gas and distillate fuel oil.

4. Emissions Unit Identification Number:
[ ] No ID
ID: 004 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	10/01/2003	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)
The nominal 317 MW combined cycle combustion turbine is comprised of one combustion turbine, which exhausts through a heat recovery steam generator (HRSG) which, is used to power a steam turbine.
Natural gas is the primary fuel; low sulfur distillate fuel oil is the back up fuel.

Applicant requested emission limitation:
Excess emissions resulting form startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and duration of excess emission shall be minimized.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Dry Low No_x (DLN) Combustor during Natural Gas firing - Burner technology to control NO_x emissions. This technology uses a two-staged 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. Water injection during Fuel Oil firing- For Oil firing cases only, this type of control injects water into the primary combustion zone with the fuel. The water serves to reduce NO_x formation by reducing the peak flame temperature. Selective Catalytic Reduction (SCR)- For both Natural Gas and Oil firing, the SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water.
2. Control Device or Method Code(s): 024, 025, 028, 065

Emissions Unit Details

1. Package Unit: Combined Cycle Combustion Turbine Generator Manufacturer: General Electric Model Number: PG 7241 FA	
2. Generator Nameplate Rating: 317 MW	
3. Incinerator Information: N/A Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	(Natural Gas firing)	2402.0	(HHV)	mmBtu/hr
	(Fuel Oil firing)	2067.6	(HHV)	mmBtu/hr
2. Maximum Incineration Rate:	N/A			
3. Maximum Process or Throughput Rate:	N/A			
4. Maximum Production Rate:	N/A			
5. Requested Maximum Operating Schedule:				
For natural gas:	24 hours/day		7 days/week	
	52 weeks/year		8760 hours/year	
For fuel oil:	24 hours/day		7 days/week	
	52 weeks/year		1000 hours/year	

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum Heat Input Rate in Field 1 based on:
Gas: 19 F, base load, with duct burner on. Performance Data Case 4.
Oil: 19 F, base load. Performance Data Case 20.
All cases of Natural Gas and Oil firing were considered in these maximums.

Maximum hours of operation on Natural Gas is 8760 hrs/yr and 1000 hrs/yr for Fuel Oil.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 004	2. Emission Point Type Code: 2

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

160-ft vertical cylindrical exhaust stack associated with the combustion turbine and heat recovery steam generator.

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

5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 19 feet
8. Exit Temperature: 287 °F	9. Actual Volumetric Flow Rate: 1280130 acfm	10. Water Vapor: N/A

11. Maximum Dry Standard Flow Rate: N/A	12. Nonstack Emission Point Height: N/A

13. Emission Point UTM Coordinates:

Zone:17 East (km):483.61 North (km):3151.12

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

Field 8 based on: Distillate Oil 100% load, 19 F case.
Field 9 based on: Distillate Oil 100% load, 19 F case.

Stack temperature and flow rate will vary with fuel, load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.

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

Segment Description and Rate: Segment __1___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined cycle mode on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e. 8760 hours).		
1. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 2.35	5. Maximum Annual Rate: 20628.94	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = 2402.0 mmBtu/hr (HHV) / 1020 mmBtu/mmscf (HHV) = 2.35 mmscf/hr Maximum Annual Rate = 8760 hrs/yr x 2402.0 mmBtu/hr / 1020 mmBtu/mmscf = 20628.94 mmscf/yr		

Segment Description and Rate: Segment __2___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined mode on No.2 distillate fuel oil. This unit is allowed to operate on No.2 distillate fuel oil for 1000 hours/yr		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand gallons burned (all liquid fuel)	
4. Maximum Hourly Rate: 14.87	5. Maximum Annual Rate: 14874.82	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = 2067.6 mmBtu/hr / 139 mmBtu/ thousand gallons = 14.87 thousand gallons/hr Maximum Annual Rate = 1000 hrs/yr x 2067.6 mmBtu/hr / 139 mmBtu/ thousand gallons =14874.82 thousand gallons/yr		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x	024	025, 028, 065	EL
CO			EL
PM/PM_{10}			EL
SO2			EL
VOC			EL
HAPS			NS

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

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual Operation 157.24 tons/year Natural Gas Firing 132.58 tons/year Fuel Oil Firing 39.85 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(30.38 \text{ lb/hr} * 7760 \text{ hr/yr})+(29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 132.58 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{79.69 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 39.85 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(30.38 \text{ lb/hr} * 6760 \text{ hr/yr})+(79.69 \text{ lb/hr} * 1000 \text{ hr/yr})+(29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 157.24 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
2. Requested Allowable Emissions and Units: 3.5 ppmvd (at 15% O_2 for Natural Gas)	4. Equivalent Allowable Emissions: 30.38 lb/hour 133.06 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppmvd (at 15% O_2 for Fuel Oil)	4. Equivalent Allowable Emissions: 79.69 lb/hour 39.85 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hrs/year of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual Operation 435.05 tons/year Natural Gas Firing 448.12 tons/year Fuel Oil Firing 35.50 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(97.13 \text{ lb/hr} * 7760 \text{ hr/yr})+(142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 448.12 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{71.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 35.50 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(97.13 \text{ lb/hr} * 6760 \text{ hr/yr})+(71.00 \text{ lb/hr} * 1000 \text{ hr/yr})+(142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 435.05 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1__ of ___2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 97.13 lb/hr for Natural Gas with duct burning 142.51 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 448.12 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions __2____ of ___2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 71.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 71.00 lb/hour 35.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual 53.63 tons/year Natural Gas Firing 50.94 tons/year Fuel Oil Firing 8.50 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(11.62 \text{ lb/hr} * 7760 \text{ hr/yr}) + (11.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 50.94 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{17.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 8.5 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(11.62 \text{ lb/hr} * 6760 \text{ hr/yr}) + (17.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (11.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 53.63 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.62 lb/hr for Natural Gas with duct burning 11.71 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 50.94 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 17.00 lb/hour 8.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Emissions based on 1000 hours/yr of Fuel Oil firing. The applicant will assume 20% opacity limit for Fuel Oil firing in lieu of the 17.00 lb/hr PM/PM_{10} limit during Fuel Oil-firing.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual 67.03 tons/year Natural Gas Firing 15.28 tons/year Fuel Oil Firing 53.50 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(3.50\ \text{lb/hr} * 7760\ \text{hr/yr}) + (3.39\ \text{lb/hr} * 1000\ \text{hr/yr})}{2000\ \text{lb/ton}} = 15.28 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{107.00\ \text{lb/hr} * 1000\ \text{hr/yr}}{2000\ \text{lb/ton}} = 53.50 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(3.50\ \text{lb/hr} * 6760\ \text{hr/yr}) + (107.00\ \text{lb/hr} * 1000\ \text{hr/yr}) + (3.39\ \text{lb/hr} * 1000\ \text{hr/yr})}{2000\ \text{lb/ton}} = 67.03 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.50 lb/hour Natural Gas	4. Equivalent Allowable Emissions: 3.50 lb/hour 15.33 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 107.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 107.00 lb/hour 53.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual 52.53 tons/year Natural Gas Firing 54.22 tons/year Fuel Oil Firing 4.00 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(11.38 \text{ lb/hr} * 7760 \text{ hr/yr})+(20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 54.22 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{8.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 4.00 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(11.38 \text{ lb/hr} * 6760 \text{ hr/yr})+(8.00 \text{ lb/hr} * 1000 \text{ hr/yr})+(20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 52.53 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.38 lb/hr for Natural Gas with duct burning 20.13 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 54.22 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hours/yr of Natural Gas-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 8.00 lb/hour 4.00 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: HAPs	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing 15.47 tons/year Fuel Oil Firing 2.47 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer/AP-42 Emission Factors	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Refer to Attachment 2 of SCA PSD Application Appendix 10.7 for full calculations.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's heat input data and AP-42 emission factors for individual HAPs.	

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___1___

1. Visible Emissions Subtype:VE20	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: 20% Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - Stack testing (USEPA Method 9 Visual Determination of Opacity) - VE limit proposed in lieu of PM/PM_{10} pound per hour limit.	
5. Visible Emissions Comment (limit to 200 characters): Florida Air Regulation Rule 62.296	

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

Continuous Monitoring System: Continuous Monitor __1___ of __6___

1. Parameter Code:EM	2. Pollutant(s): NO_x
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
1. Continuous Monitor Comment (limit to 200 characters): Continuous compliance with any emission limitations will be demonstrated through compliance with Rule 62.4.070 and 62-204.800(7), F.A.C. to avoid PSD review. Rule: 40 CFR Part 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor __2___ of __6___

1. Parameter Code:WTF	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Rule: New Source Performance Standards 40 CFR 60, Subpart GG	

Continuous Monitoring System: Continuous Monitor ___3__ of __6___

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Fuel oil flow monitoring will be operated pursuant of CFR 40 Part 75	

Continuous Monitoring System: Continuous Monitor ___4__ of ___6__

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Natural gas flow monitor will be installed pursuant to CFR 40 Part 75	

Continuous Monitoring System: Continuous Monitor __5___ of ___6__

1. Parameter Code: O_2	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source This CEM will be installed on the HRSG stack. Required by 40 CFR Part 75	

Continuous Monitoring System: Continuous Monitor __6___ of ___6__

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM for opacity will be installed before operation of the emission source. This CEM will be installed on the HRSG stack. Required by 40 CFR Part 75	

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

Supplemental Requirements

1. Process Flow Diagram
   [X] Attached, Document ID:Attachment D [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
   [X] Attached, Document ID:Attachment E [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
   [X] Attached, Document ID:SCA BACT Analysis Appendix 10.7, Section 3.0

4. Description of Stack Sampling Facilities
   [X] Attached, Document ID:Attachment F [ ] Not Applicable [ ] Waiver Requested

5. Compliance Test Report
   [ ] Attached, Document ID:________________
   [ ] Previously submitted, Date:_______________
   [X] Not Applicable

6. Procedures for Startup and Shutdown
   [ ] Attached, Document ID:____________ [X] Not Applicable [ ] Waiver Requested

7. Operation and Maintenance Plan
   [ ] Attached, Document ID:____________ [X] Not Applicable [ ] Waiver Requested

8. Supplemental Information for Construction Permit Application
   [X] Attached, Document ID:SCA PSD Application Appendix 10.7

9. Other Information Required by Rule or Statute
   [ ] Attached, Document ID:________ [X] Not Applicable

10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

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

Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator operating in combined cycle (CCCT) mode with one heat recovery steam generator (HRSG) having a nominal rating of 317 MW. The CCCT/HRSG will be capable of firing both natural gas and distillate fuel oil.

4. Emissions Unit Identification Number:
[ ] No ID
ID: 005 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	10/01/2003	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)
The nominal 317 MW combined cycle combustion turbine is comprised of one combustion turbine, which exhausts through a heat recovery steam generator (HRSG) which, is used to power a steam turbine.
Natural gas is the primary fuel; low sulfur distillate fuel oil is the back up fuel.

Applicant requested emission limitation:
Excess emissions resulting form startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and duration of excess emission shall be minimized.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Dry Low No_x (DLN) Combustor during Natural Gas firing - Burner technology to control NO_x emissions. This technology uses a two-staged 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.

Water injection during Fuel Oil firing- For Oil firing cases only, this type of control injects water into the primary combustion zone with the fuel. The water serves to reduce NO_x formation by reducing the peak flame temperature.

Selective Catalytic Reduction (SCR)- For both Natural Gas and Oil firing, the SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water.

2. Control Device or Method Code(s): 024, 025, 028, 065

Emissions Unit Details

1. Package Unit: Combined Cycle Combustion Turbine Generator
   Manufacturer: General Electric
   Model Number: PG 7241 FA
2. Generator Nameplate Rating: 317 MW
3. Incinerator Information: N/A
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	(Natural Gas firing)	2402.0	(HHV)	mmBtu/hr
	(Fuel Oil firing)	2067.6	(HHV)	mmBtu/hr
2. Maximum Incineration Rate:	N/A			
3. Maximum Process or Throughput Rate:	N/A			
4. Maximum Production Rate:	N/A			

5. Requested Maximum Operating Schedule:

For natural gas:	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year
For fuel oil:	24 hours/day	7 days/week
	52 weeks/year	1000 hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum Heat Input Rate in Field 1 based on:
Gas: 19 F, base load, with duct burner on. Performance Data Case 4.
Oil: 19 F, base load. Performance Data Case 20.
All cases of Natural Gas and Oil firing were considered in these maximums.

Maximum hours of operation on Natural Gas is 8760 hrs/yr and 1000 hrs/yr for Fuel Oil.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 005	2. Emission Point Type Code: 2

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

160-ft vertical cylindrical exhaust stack associated with the combustion turbine and heat recovery steam generator.

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

5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 19 feet
8. Exit Temperature: 287 °F	9. Actual Volumetric Flow Rate: 1280130 acfm	10. Water Vapor: N/A

11. Maximum Dry Standard Flow Rate: N/A	12. Nonstack Emission Point Height: N/A

13. Emission Point UTM Coordinates:

Zone:17 East (km):483.61 North (km):3151.08

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

Field 8 based on: Distillate Oil 100% load, 19 F case.
Field 9 based on: Distillate Oil 100% load, 19 F case.

Stack temperature and flow rate will vary with fuel, load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.

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

Segment Description and Rate: Segment __1___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined cycle mode on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e. 8760 hours).		
1. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 2.35	5. Maximum Annual Rate: 20628.94	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

Maximum Hourly Rate = $\frac{\text{2402.0 mmBtu/hr (HHV)}}{\text{1020 mmBtu/mmscf (HHV)}}$ = 2.35 mmscf/hr

Maximum Annual Rate = $\frac{\text{8760 hrs/yr x 2402.0 mmBtu/hr}}{\text{1020 mmBtu/mmscf}}$ = 20628.94 mmscf/yr

Segment Description and Rate: Segment __2___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined mode on No.2 distillate fuel oil. This unit is allowed to operate on No.2 distillate fuel oil for 1000 hours/yr		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand gallons burned (all liquid fuel)	
4. Maximum Hourly Rate: 14.87	5. Maximum Annual Rate: 14874.82	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

9. Segment Comment (limit to 200 characters):

Maximum Hourly Rate = $\frac{\text{2067.6 mmBtu/hr}}{\text{139 mmBtu/ thousand gallons}}$ = 14.87 thousand gallons/hr

Maximum Annual Rate = $\frac{\text{1000 hrs/yr x 2067.6 mmBtu/hr}}{\text{139 mmBtu/ thousand gallons}}$ =14874.82 thousand gallons/yr

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x	024	025, 028, 065	EL
CO			EL
PM/PM_{10}			EL
SO2			EL
VOC			EL
HAPS			NS

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

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual Operation 157.24 tons/year Natural Gas Firing 132.58 tons/year Fuel Oil Firing 39.85 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(30.38 \text{ lb/hr} * 7760 \text{ hr/yr})+(29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 132.58 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{79.69 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 39.85 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(30.38 \text{ lb/hr} * 6760 \text{ hr/yr})+(79.69 \text{ lb/hr} * 1000 \text{ hr/yr})+(29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 157.24 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
2. Requested Allowable Emissions and Units: 3.5 ppmvd (at 15% O_2 for Natural Gas)	4. Equivalent Allowable Emissions: 30.38 lb/hour 133.06 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppmvd (at 15% O_2 for Fuel Oil)	4. Equivalent Allowable Emissions: 79.69 lb/hour 39.85 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hrs/year of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: CO

2. Total Percent Efficiency of Control:

3. Potential Emissions:

Annual Operation	435.05 tons/year
Natural Gas Firing	448.12 tons/year
Fuel Oil Firing	35.50 tons/year

4. Synthetically Limited? [ ]

5. Range of Estimated Fugitive Emissions:
[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
Reference: Manufacturer

7. Emissions Method Code:
0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(97.13\ lb/hr * 7760\ hr/yr)+(142.51\ lb/hr * 1000\ hr/yr)}{2000\ lb/ton} = 448.12 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{71.00\ lb/hr * 1000\ hr/yr}{2000\ lb/ton} = 35.50 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(97.13\ lb/hr * 6760\ hr/yr)+(71.00\ lb/hr * 1000\ hr/yr)+(142.51\ lb/hr * 1000\ hr/yr)}{2000\ lb/ton} = 435.05 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1__ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 97.13 lb/hr for Natural Gas with duct burning 142.51 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 448.12 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions __2____ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 71.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 71.00 lb/hour 35.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual 53.63 tons/year Natural Gas Firing 50.94 tons/year Fuel Oil Firing 8.50 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(11.62\ lb/hr * 7760\ hr/yr)+(11.71\ lb/hr * 1000\ hr/yr)}{2000\ lb/ton} = 50.94 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{17.00\ lb/hr * 1000\ hr/yr}{2000\ lb/ton} = 8.5 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(11.62\ lb/hr * 6760\ hr/yr)+(17.00\ lb/hr * 1000\ hr/yr)+(11.71\ lb/hr * 1000\ hr/yr)}{2000\ lb/ton} = 53.63 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.62 lb/hr for Natural Gas with duct burning 11.71 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 50.94 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 17.00 lb/hour 8.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Emissions based on 1000 hours/yr of Fuel Oil firing. The applicant will assume 20% opacity limit for Fuel Oil firing in lieu of the 17.00 lb/hr PM/PM_{10} limit during Fuel Oil-firing.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual 67.03 tons/year Natural Gas Firing 15.28 tons/year Fuel Oil Firing 53.50 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0

8. Calculation of Emissions (limit to 600 characters):

Potential annual emissions (using highest hourly emissions based on worst case ambient conditions):

CCCT Natural Gas and duct firing (with power augmentation):

$$\frac{(3.50 \text{ lb/hr} * 7760 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 15.28 \text{ tons per year}$$

Fuel Oil Firing:

$$\frac{107.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 53.50 \text{ tons per year}$$

Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation):

$$\frac{(3.50 \text{ lb/hr} * 6760 \text{ hr/yr}) + (107.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 67.03 \text{ tons per year}$$

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.50 lb/hour Natural Gas	4. Equivalent Allowable Emissions: 3.50 lb/hour 15.33 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 107.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 107.00 lb/hour 53.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: Annual 52.53 tons/year Natural Gas Firing 54.22 tons/year Fuel Oil Firing 4.00 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): (11.38 lb/hr * 7760 hr/yr)+(20.13 lb/hr * 1000 hr/yr) / 2000 lb/ton = 54.22 tons per year Fuel Oil Firing: 8.00 lb/hr * 1000 hr/yr / 2000 lb/ton = 4.00 tons per year Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): (11.38 lb/hr * 6760 hr/yr)+(8.00 lb/hr * 1000 hr/yr)+(20.13 lb/hr * 1000 hr/yr) / 2000 lb/ton = 52.53 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.	

<u>Allowable Emissions</u> Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.38 lb/hr for Natural Gas with duct burning 20.13 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 54.22 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hours/yr of Natural Gas-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

<u>Allowable Emissions</u> Allowable Emissions ___2___ of ___2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 8.00 lb/hour 4.00 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: HAPs	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing 15.47 tons/year Fuel Oil Firing 2.47 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Manufacturer/AP-42 Emission Factors	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Refer to Attachment 2 of SCA PSD Application Appendix 10.7 for full calculations.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's heat input data and AP-42 emission factors for individual HAPs.	

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___1___

1. Visible Emissions Subtype:VE20	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: 20% Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - Stack testing (USEPA Method 9 Visual Determination of Opacity) - VE limit proposed in lieu of PM/PM_{10} pound per hour limit.	
5. Visible Emissions Comment (limit to 200 characters): Florida Air Regulation Rule 62.296	

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

Continuous Monitoring System: Continuous Monitor __1___ of __6__

1. Parameter Code:EM	2. Pollutant(s): NO_x
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
6. Continuous Monitor Comment (limit to 200 characters): Continuous compliance with any emission limitations will be demonstrated through compliance with Rule 62.4.070 and 62-204.800(7), F.A.C. to avoid PSD review. Rule: 40 CFR Part 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor __2___ of __6__

1. Parameter Code:WTF	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Rule: New Source Performance Standards 40 CFR 60, Subpart GG	

Continuous Monitoring System: Continuous Monitor ___3__ of __6___

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Fuel oil flow monitoring will be operated pursuant of CFR 40 Part 75	

Continuous Monitoring System: Continuous Monitor ___4__ of ___6__

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Natural gas flow monitor will be installed pursuant to CFR 40 Part 75	

Continuous Monitoring System: Continuous Monitor __5___ of ___6__

1. Parameter Code: O_2	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source This CEM will be installed on the HRSG stack. Required by 40 CFR Part 75	

Continuous Monitoring System: Continuous Monitor __6___ of ___6__

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM for opacity will be installed before operation of the emission source. This CEM will be installed on the HRSG stack. Required by 40 CFR Part 75	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID:Attachment D [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID:Attachment E [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID:SCA BACT Analysis Appendix 10.7, Section 3.0
4. Description of Stack Sampling Facilities [X] Attached, Document ID:Attachment F [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:___________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:___________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID:SCA PSD Application Appendix 10.7
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_______ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

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

10-cell linear mechanical draft cooling tower equipped with drift eliminators for control of PM/PM_{10} emissions.

4. Emissions Unit Identification Number:

[ ] No ID

ID: 006 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	10/01/2003	49	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

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

Emissions Unit Details

1. Package Unit: Manufacturer:		Model Number:
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: N/A Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		mmBtu/hr
2. Maximum Incineration Rate:	N/A	
3. Maximum Process or Throughput Rate:	125,000 gal/min	
4. Maximum Production Rate:	N/A	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Maximum process rate (Field 3) is cooling tower water recirculation rate.		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 006	2. Emission Point Type Code: 3

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Cooling tower consists of 10 cells.

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

5. Discharge Type Code: V	6. Stack Height: 44.7 feet	7. Exit Diameter: 34 feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: N/A

11. Maximum Dry Standard Flow Rate: N/A	12. Nonstack Emission Point Height: N/A

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 483.50 North (km): 3,151.02

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

Cooling tower consists of 10 cells with 10 individual exhaust fans. Stack height and diameter provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.

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

Segment Description and Rate: Segment __1___ of __1___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Cooling tower water recirculation flow rate.		
1. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Thousand gallons transferred	
4. Maximum Hourly Rate: 7500	5. Maximum Annual Rate: 65700000	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM/PM_{10}	015		NS

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

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 4.6 lb/hr 20.3 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 4.6 Reference: AP-42, Section 13.4	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

(125,000 gal/min) * (0.002 gal/100 gal) * (3704 lb PM/10^6 lb water) *
(8.345 lb/gal water) * (60min/hr) = 4.6 lb/hr

(4.6 lb/hr) * (8760 hr/yr) * (1 ton/2000 lb) = 20.3 tons/yr PM/PM_{10}

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
Emission calculations based on manufacturer's guarantee.

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___1___

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

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID:Attachment D [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:____________ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID:SCA BACT Analysis Appendix 10.7, Section 3.0
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: __________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________________ [ ] Previously submitted, Date:_______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:____________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:____________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID:SCA PSD Application Appendix 10.7
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: ________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II Nox Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[ ] 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.

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

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

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

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

No. 2 Distillate Fuel Oil Storage Tank (1,680,000 gal).

4. Emissions Unit Identification Number:

[ ] No ID

ID: 007 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	10/01/2003	49	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This distillate fuel oil storage tank (1,680,000 gal) is reported as an emission unit because it is subject to regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb.

The tank is a vertical fixed roof design.

<u>Emissions Unit Control Equipment</u>

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

<u>Emissions Unit Details</u>

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating: MW	
3. Incinerator Information: N/A Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	mmBtu/hr	
2. Maximum Incineration Rate:	N/A	
3. Maximum Process or Throughput Rate:	28800	thousand gal/yr
4. Maximum Production Rate:	N/A	
5. Requested Maximum Operating Schedule:		
6. Operating Capacity/Schedule Comment (limit to 200 characters): The maximum throughput rate corresponds to the use of No. 2 distillate fuel oil for 1,000 hours per year.		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 007	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below.

1. Storage Loss: Emissions 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: 0 feet	7. Exit Diameter: 0 feet
8. Exit Temperature: 70 °F	9. Actual Volumetric Flow Rate: 0 acfm	10. Water Vapor: N/A

11. Maximum Dry Standard Flow Rate: N/A	12. Nonstack Emission Point Height: 40 feet

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 483.25 North (km): 3,150.93

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

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

Segment Description and Rate: Segment __1___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Storage Loss: Emissions 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).		
1. Source Classification Code (SCC): 4-03-010-19	3. SCC Units: Thousand Gallons Stored	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor: 1680
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): (1680000 gal stored)/(1000 gal) = 1680 capacity factor		

Segment Description and Rate: Segment __2___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): 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.		
2. Source Classification Code (SCC): 4-03-010-21	3. SCC Units: Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor: 28800
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
9. Segment Comment (limit to 200 characters): (28800000 gal of fuel oil consumed by the turbines per year)/(1000 gal) = 28800 gal/yr		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions:	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5 (EPA TANKS Program)
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

<u>Allowable Emissions</u> Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: N/A
2. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): As specified in 40 CFR 60.116(a) and (b), Subpart Kb	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Rule: 40 CFR 60.Kb – Standards of Performance for Volitile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.	

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___1___

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

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

Continuous Monitoring System: Continuous Monitor __1___ of __1___

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

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

Attachment A
Applicable Regulations

List of Applicable Regulations

FDEP Title V Core List (effective 3/25/95) incorporated by reference

40 CFR Part 60, Subpart A – Standards of Performance for New Stationary Sources

40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines

Part 70 – State Operating Permit Programs

Section 70.1 - Program Overview

Section 70.2 - Definitions

Section 70.3 - Applicability

Section 70.4 - State Program Submittals and Transition

Section 70.5 - Permit Applications

Section 70.6 - Permit Content

Section 70.7 - Permit Issuance, Renewal, Reopenings, and Revisions

Section 70.8 – Permit Review by the EPA and Affected States

Section 70.9 – Fee Determination and Certification

Section 70.10 – Federal Oversight and Sanctions

Section 70.11 – Requirements for Enforcement Authority

Part 72 – Regulations on Permits

Subpart A – Acid Rain program General Provisions

Section 72.1 Purpose and Scope

Section 72.2 – Definitions

Section 72.3 – Measurements, Abbreviations, and Acronyms

Section 72.4 – Federal Authority

Section 72.5 – State Authority

Section 72.6 – Applicability

Section 72.9 – Standard Requirements

Section 72.10 – Availability of Information

Section 72.11 – Computation of Time

Section 72.12 – Administrative Appeals

Section 72.13 – Incorporation by Reference

Subpart B – Designated Representative

Section 72.20 – Authorization and Responsibilities of the Designated

Section 72.21 – Submissions

Section 72.22 – Alternate Designed Representative

Section 72.23 – Changing the Seignated Representative, Alternate Designated

Section 72.24 – Certificate of Representation

Section 72.25 – Objections

Subpart C – Acid Rain Application

Section 72.30 – Requirements to Apply

Section 72.31 – Information Requirements for Acid Rain Permit

Section 72.32 – Permit Application Shield and Binding Effect of Permit

Section 72.33 – Identification if Dispatch System

Subpart D – Acid Rain Compliance Plan and Compliance Options

Section 72.40 – General

Subpart E – Acid Rain Permit Conditions

Section 72.50 – General

Section 72.51 – Permit Shield

Subpart F – Federal Acid Rain Permit Issuance Procedure

Section 72.60 – General

Section 72.61 – Completeness

Section 72.62 – Draft Permit

Section 72.63 – Administrative Board

Section 72.64 – Statement of Basis

Section 72.65 – Public Notice of Opportunities for Public Comment
Section 72.66 – Public Comments

Section 72.67 – Opportunity for Public Hearing

Section 72.68 – Response to Comments

Section 72.69 – Issuance and effective Date of Acid Rain Permits

Subpart G – Acid Rain Phase II Implementation

Section 72.70 – Relationship to Title V Operating Permit Program

Section 72.71 – Approval of State Programs – General

Section 72.72 – State Permit Program Approval Criteria

Section 72.73 – State Issue of Phase II Permits

Section 73.35 – Compliance

Section 73.36 – Banking

Section 73.37 – Account Error and Dispute Resolution

Section 73.38 – Closing of Accounts

Subpart D – Allowance Transfers

Section 73.50 – Scope and Submission of Transfers

Section 73.51 – Prohibition

Section 73.52 – EPA Recordation

Section 73.53 – Notification

Subpart E – Auctions, Direct Sales, and Independent Power Producers Written

Section 73.70 – Auctions

Section 73.71 – Bidding

Section 73.72 – Direct Sales

Section 73.73 – Selegation of Auctions and Sales and Termination of Auctions

Section 73.74 – Independent Power Producers Written Guarantee

Section 73.75 – Application for an IPP Written Guarantee

Section 73.76 – Approval and Exercise of the IPP Written Guarantee

Section 73.77 – Relationship of Independent Power Producers Written Guarantee

Section 75.5 – Prohibitions

Section 75.6 – Incorporation by Reference

Section 76.7 – EPA Study

Section 76.8 – [Reserved]

Subpart – Monitoring Provisions

Section 75.10 – General Operating Requirements

Section 75.11 – Specific Provisions for Monitoring SO2 Emissions

Section 75.12 – Specific Provisions for Monitoring NOx Emissions (NOx and Flow)

Section 75.13 – Specific Provisions for Monitoring CO2 Emissions

Section 75.14 – Specific Provisions for Monitoring Capacity

Section 75.15 – Specific Provisions for Monitoring SO2 Emissions Removal By

Section 75.16 – Specific Provisions for Monitoring Emissions from Common, By

Section 75.17 – Specific Provisions for Monitoring Emissions from Common, By

Section 75.18 – Specific Provisions for Monitoring Emissions from Common and

Section 75.41 – Precision Criteria

Section 75.42 – Reliability Criteria

Section 75.43 – Accessibility Criteria

Section 75.44 – Timeliness Criteria

Section 75.45 – Daily Quality Assurance Criteria

Section 75.46 – Missing Data Substitution Criteria

Section 75.47 – Criteria for a Class of Affected Units

Section 75.48 – Petition for an Alternative Monitoring System

Subpart F – Recordkeeping Requirements

Section 75.50 – General Recordkeeping Provisions

Section 75.51 – General Recordkeeping Provisions for Specific Situations

Section 75.52 – Certifications, Quality Assurance and Quality Control Record

Section 75.53 – Monitoring Plan

Subpart G – Reporting Requirements

Section 75.60 – General Provisions

Section 75.61 – Notification and Recertification Test Dates

Section 75.62 – Monitoring Plan

Section 75.63 – Certification or Recertification Applications

Section 75.64 – Quarterly Reports

Section 75.65 – Capacity Reports

Section 75.66 – Petitions to the Administrator

Section 75.67 – Retired Units Petitions

Part 76 – EPA Regulations on Acid Rain Nitrogen Oxides

Section 76.1 – Applicability

Section 76.2 – Definitions

Section 76.3 – General Acid Rain Program Provisions

Section 76.4 –Incorporation by Reference

Section 76.5 – NOx Emission Limitations for Group 1 Boilers

Section 76.6 – NOx Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 – Revised NOx Emission Limitations for Group 1, Phase II Boilers

Section 76.8 – Early Election for Group 1, Phase II Boilers

Section 76.9 – Permit Application and Compliance Plans

Section 76.10 – Alternative Emission Limitations

Section 76.11 – Emissions Averaging

Section 76.12 – Phase I NOx Compliance Extensions

Section 76.13 – Compliance and Excess Emissions

Section 76.14 – Monitoring, Recordkeeping, and Reporting

Section 76.15 – Test Methods and Procedures

Section 76.16 – [Reserved]

Part 77 – Excess Emissions

State Applicable Requirements

Chapter 62-4, F.A.C.; PERMITS

62-4.055 – Permit Processing

Chapter 62-210, F.A.C.; STATIONARY SOURCES – GENERAL REQUIREMENTS

62-210.550 – Stack Height Policy

62-210.700 Excess Emissions

Chapter 62-212, F.A.C.; STATIONARY SOURCES – PRECONSTRUCTION REVIEW

62-212.300 – General Preconstruction Review Requirements

62-212.400 – Prevention of Significant Deterioration

62-212.410 – Best Available Control Technology

Chapter 62-213, F.A.C.; OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION

62-213.413 – Fast-Track Revisions of Acid Rain Parts

Chapter 62-214, F.A.C.; REQUIREMENTS FOR SOURCES SUBJECT TO THE FEDERAL ACID RAIN PR

62-214.300 – Applicability

62-214.320 – Applications

62-214.330 – Acid Rain Compliance Plan and Compliance Options

62-214.350 – Certification

62-214.370 – Revisions Administration Corrections

62-214.420 – Acid Rain Part Content

62-214.430 – Implementation and Termination of Compliance Options

Chapter 62-272, F.A.C.; AMBIENT AIR QUALITY STANDARDS

62-272.500 – Maximum Allowable Increases

Chapter 62-273, F.A.C.; AIR POLLUTION EPISODES

62-273.300 – Air Pollution Episodes

62-273.400 – Air Alert

62-273.500 – Air Warning

62-273.600 – Air Emergency

Chapter 62-296, F.A.C.; STATIONARY SOURCES – EMISSION STANDARDS

62-296.405 – Fossil Fuel Steam Generators

Chapter 62-297, F.A.C.; STATIONARY SOURCES – EMISSIONS MONITORING

62-297.401 – Compliance Test Methods

62-297.440 – Supplementary Test Procedures

62-297.520 – EPA Performance Specifications

62-297.620 – Exceptions and Approval of Alternate Procedures and Requirements

62-297.310 – General Test Requirements

Subpart F – Energy Conservation and Renewable Energy Reserve

Section 73.80 – Operation of Allowance Reserve Program for Conservation..

Section 73.81 – Quantified Conservation Measures and Renewable Energy

Section 73.82 – Application for Allowances from Reserve Program

Section 73.83 – Secretary of Energy's Action on New Income Neutality

Section 73.84 – Administrator's Action on Applications

Section 73.85 – Administrator Review of the Reserve Program

Section 73.86 – State Regulatory Autonomy, Appendix A to Subpart F….List of

Part 75 – Emission Monitoring

Subpart A – General

Section 75.1 – Purpose and Scope

Section 75.2 – Applicability

Section 75.3 – General Acid Rain Program Provisions

Section 75.4 – Compliance Dates

Subpart C – Operation and Maintenance Requirements

Section 75.20 – Certification and Recertification Procedures

Section 75.21 – Quality Assurance and Quality Control Requirements

Section 75.22 – Reference Test Methods

Section 75.23 – Alternatives to ASTM Methods

Section 75.24 – Out-of-Control Periods

Subpart D – Missing Data Substitution Procedures

Section 75.30 – General Procedures

Section 75.31 – Initial Missing Data Procedures

Section 75.32 – Determinations of Monitor Data Availability for Standard Missing Data

Section 75.33 – Standard Missing Data Procedures

Section 75.34 – Units with Add-on Emission Controls

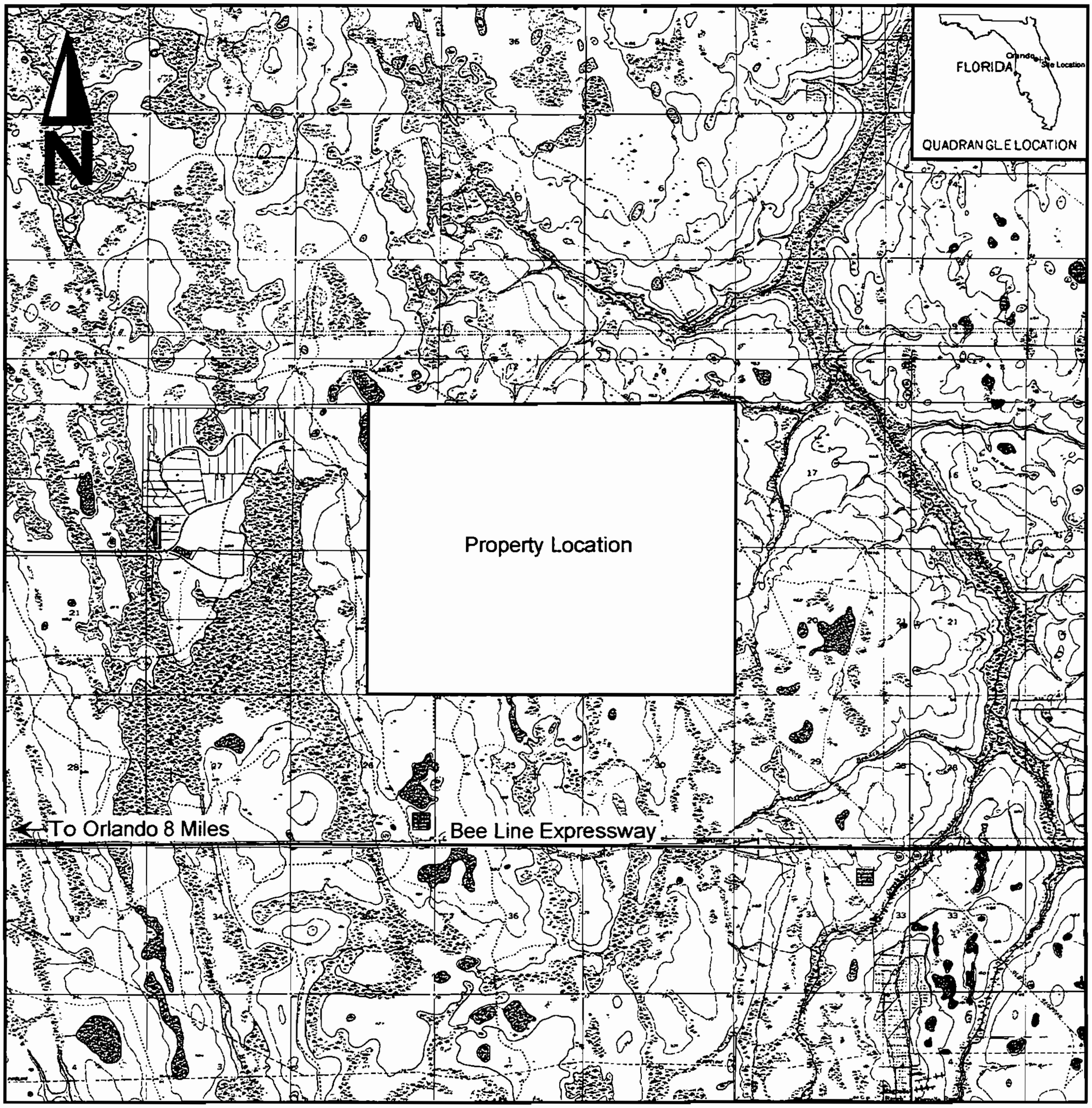
Subpart E – Alternative Monitoring Systems

Subpart 75.40 – General Demonstration Requirements

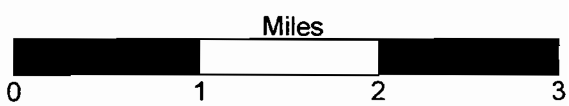
1,680,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Stanbdards of Performance for Volatile Organic Liquid Storage Vellessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 19984.
40 CFR 60.116b, Monitoring of OpOperations	The owneror or poperator shall keep records according to the provisions of 40 cCFR 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 f air pollutants without the applicalbe 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 B
Area Map Showing Facility Location



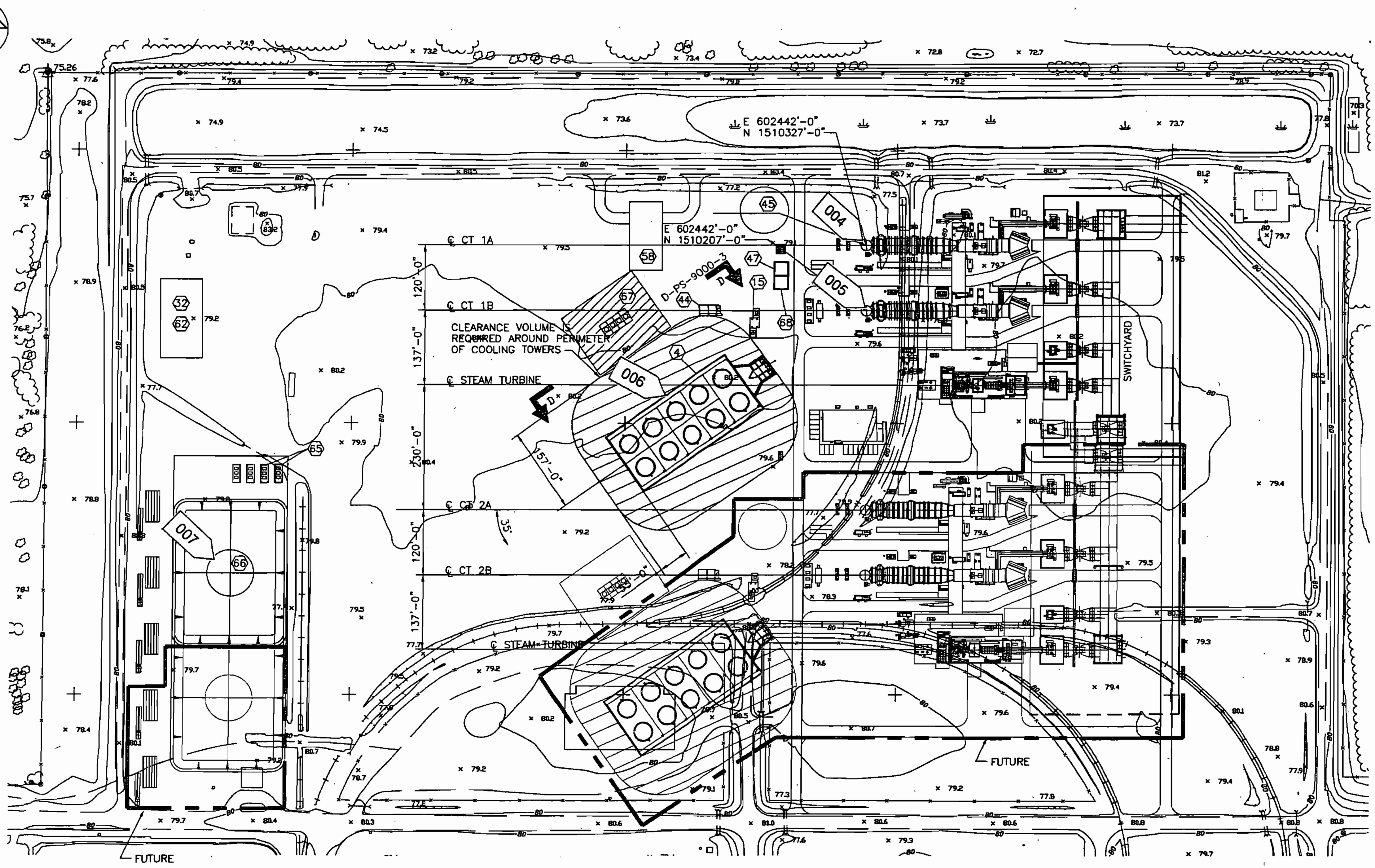
Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)



Stanton Energy Center
Property Location

Attachment C
Facility Plot Plan

D-PS-9000-1



NOTES:

NEW STACK COORDINATES BASED ON NAD83 FLORIDA STATE PLANES, EASTERN ZONE, U.S. FOOT:

CENTER UNIT 1A HRSG STACK:	E 602442'-0" N 1510327'-0"
CENTER UNIT 1B HRSG STACK:	E 602442'-0" N 1510207'-0"
CENTER UNIT 2A HRSG STACK:	E 602442'-0" N 1509840'-0"
CENTER UNIT 2B HRSG STACK:	E 602442'-0" N 1509720'-0"

NEW STACK COORDINATES BASED ON NAD83 UTM, ZONE 16 NORTH, METER:

CENTER UNIT 1A HRSG STACK:	E 1071425.2056 N 3165216.3816
CENTER UNIT 1B HRSG STACK:	E 1071427.0434 N 3165179.7166
CENTER UNIT 2A HRSG STACK:	E 1071432.6637 N 3165067.5830
CENTER UNIT 2B HRSG STACK:	E 1071434.5014 N 3165030.9181

⬡ DENOTES EQUIP. NO. – SEE D-PS-9000-2 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=60'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=400'-0"

CAD 9000-1D.DWG AutoCad SHW-14

PRELIMINARY

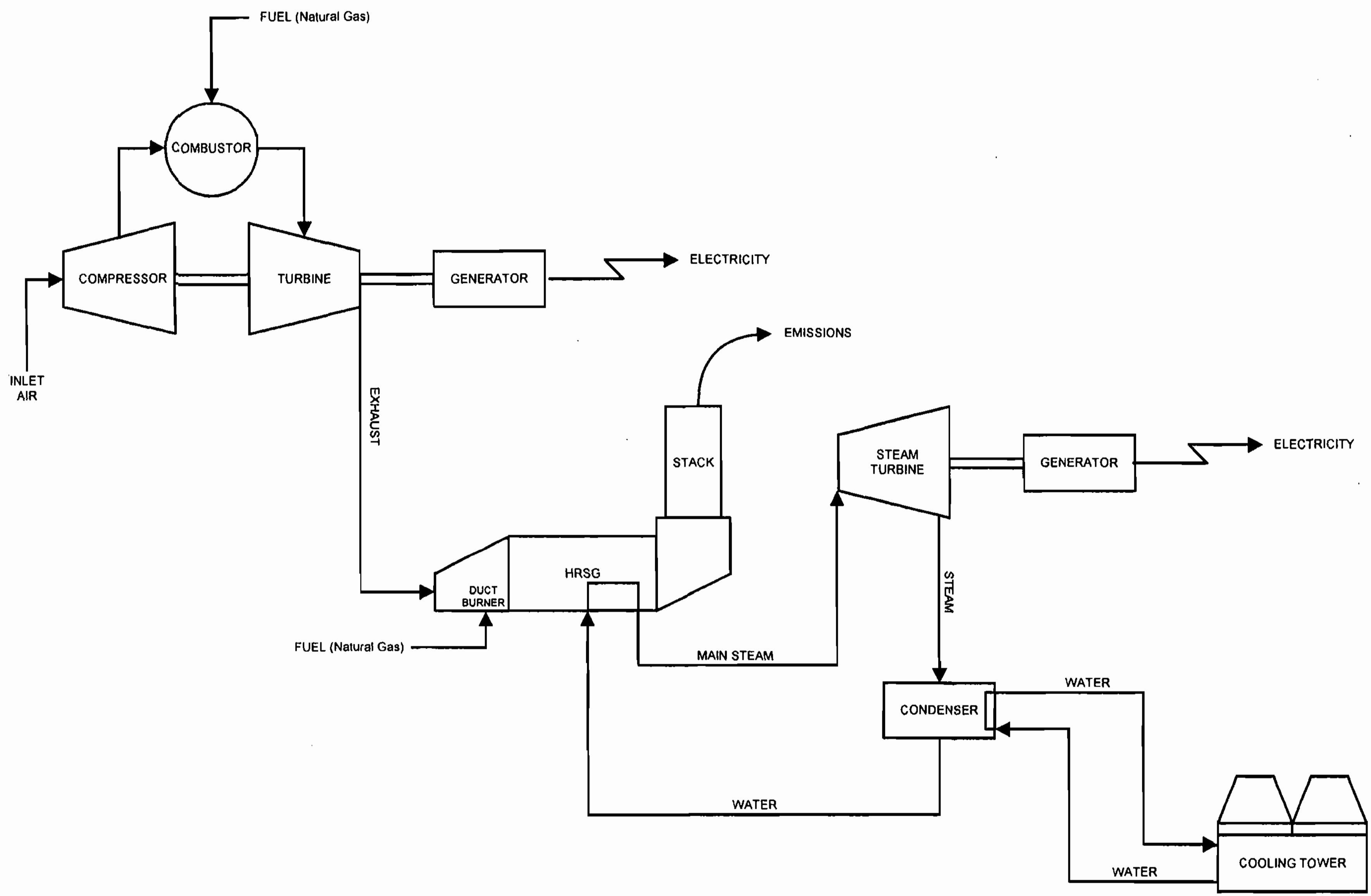
Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"

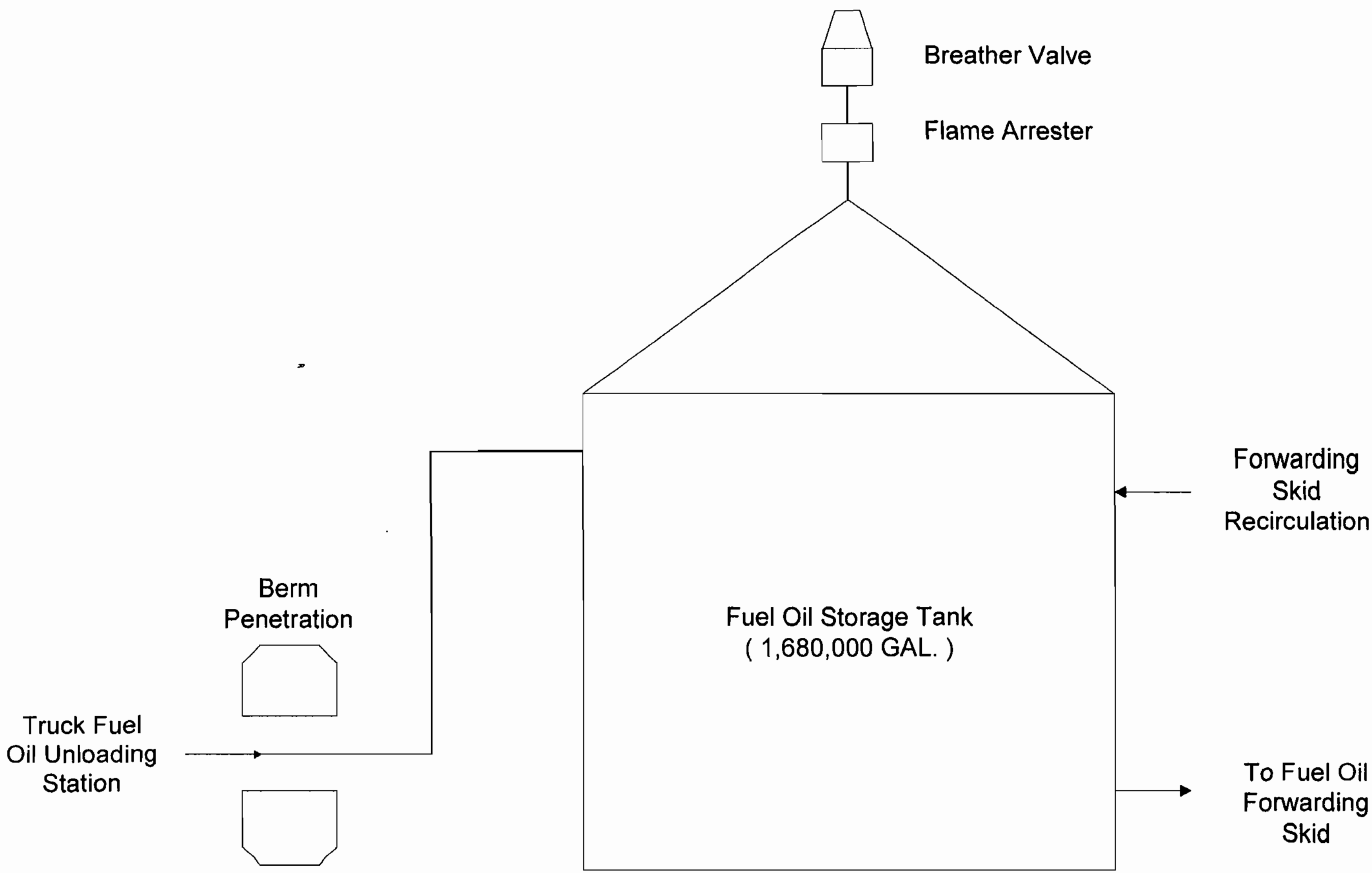
Revision	Date	Description	By
REVISION D	01/16/00	1. REVISED TITLE BLOCK	SHW
REVISION C	12/7/00	1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	DWR
REVISION B	10/24/00	1. ADDED SERVICE WATER COOLER 1. ADDED LOCATION OF FUTURE BLOCK.	SHW
REVISION A	9/22/00	ISSUED FOR REVIEW	SHW

DESIGNED	DRAWN	CHECKED	SCALE	PROJECT I.D.	DRAWING NUMBER	REV.
SHW	SHW		1"=200'-0"		D-PS-9000-1	D

Attachment D
Process Flow Diagram



Combined Cycle Combustion Turbine Process Flow Diagram


Breather Valve
Flame Arrester
Forwarding Skid Recirculation
Berm Penetration
Fuel Oil Storage Tank
(1,680,000 GAL.)
Truck Fuel Oil Unloading Station
To Fuel Oil Forwarding Skid

Attachment E
Fuel Analysis

The primary fuel for the Project is natural gas and the backup fuel is low sulfur (0.05 percent) No. 2 fuel oil. Operation on oil is proposed to be limited to 1,000 hours per year, per unit. Tables E-1 and E-2 present typical property values for the primary and backup fuels, respectively.

Table E-1 Natural Gas Properties				
Parameter	Mole, percent	Gal/Mcf**	Btu*	Rel Den*
C6+	0.075	0.029	60.0	0.00015
Propane	0.665	0.182	342.0	0.00077
I-Butane	0.152	0.049	101.0	0.00023
N-Butane	0.130	0.041	87.0	0.00020
I-Pentane	0.040	0.015	33.0	0.00008
N-Pentane	0.020	0.007	16.0	0.00004
Nitrogen	0.309	0.000	0.0	0.00023
Methane	95.067	0.000	1,9209.0	0.04006
CO_2	0.881	0.000	0.0	0.00102
Ethane	2.661	0.708	957.0	0.00210
Totals	100.0	1.031	2,0798.0	0.04488

*The component C6+ is assumed to be C6H6 only.

**The density for each component is evaluated under a pressure of 14.64 psia.

Table E-2 Typical No. 2 Fuel Oil Properties	
Parameter	Value
Ash Content, percent wt	0.001
Sulfur Content by XRF, percent wt	<0.05
Water Content KF, percent wt	<0.50 percent
Density, kg/l at 15 C	0.8422
Gross Heat Value, Btu/gal	138,000
Net Heat Value, Btu/gal	129,575
Gross Heat Value, Btu/lb	19,756
Net Heat Value, Btu/lb	18,550
Arsenic, ppm	<0.05
Beryllium, ppm	<0.05
Mercury, ppm	<0.05
Lead, ppm	0.07

Attachment F
Stack Sampling Facilities

The stack sampling facilities will be installed in accordance with Rule 62-297 310 (6).

Attachment G
Operating Matrix

Table 1
Combustion Turbine Operating Scenarios

Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Power Augmentation	Duct Burner
Natural Gas							
1	19	100	X	X			
2	19	75	X	X			
3	19	50	X	X			
4	19	100	X	X			X
5	45	100	X	X			
6	45	75	X	X			
7	45	50	X	X			
8	45	100	X	X			X
9	60	100	X	X	X	X	X
10	70	100	X	X	X		
11	70	75	X	X			
12	70	50	X	X			
13	70	100	X	X	X		X
14	95	100	X	X	X		
15	95	75	X	X			
16	95	50	X	X			
17	95	100	X	X	X	X	X
18	95	100	X	X	X	X	X
19	95	100	X	X	X		X
Distillate Fuel Oil							
20	19	100	X	X			
21	19	75	X	X			
22	19	50	X	X			
23	45	100	X	X			
24	70	100	X	X	X		
25	95	100	X	X	X		

Attachment H
Acid Rain Permit Application

Will be submitted by a Orlando Utility Commission, Kissimmee Utility Authority, Florida Municipal Power Authority, and Southern Company – Florida, LLC designated representative.

Attachment I
TANKS Calculation

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	007
City:	Pensacola
State:	Florida
Company:	OUC
Type of Tank:	Vertical Fixed Roof Tank
Description:	Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft):	40.00
Diameter (ft):	82.23
Liquid Height (ft):	38.50
Avg. Liquid Height (ft):	19.25
Volume (gallons):	1,680,000.00
Turnovers:	17.14
Net Throughput (gal/yr):	28,800,000.00
Is Tank Heated (y/n):	N

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):	43.12

Breather Vent Settings

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

Meteorological Data used in Emissions Calculations: Orlando, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	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	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.32	68.84	79.80	72.34	0.0103	0.0086	0.0122	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Annual Emission Calculations	
Standing Losses (lb):	633.8478
Vapor Space Volume (cu ft):	204,547.5111
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9795
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	204,547.5111
Tank Diameter (ft):	82.2300
Vapor Space Outage (ft):	38.5162
Tank Shell Height (ft):	40.0000
Average Liquid Height (ft):	19.2500
Roof Outage (ft):	17.7662
Roof Outage (Dome Roof)	
Roof Outage (ft):	17.7662
Dome Radius (ft):	43.1150
Shell Radius (ft):	41.1150
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Daily Avg. Liquid Surface Temp. (deg. R):	533.9945
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0067
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.9205
Daily Vapor Pressure Range (psia):	0.0035
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg R):	533.9945
Daily Min. Liquid Surface Temp. (deg R):	528.5143
Daily Max. Liquid Surface Temp. (deg R):	539.4746
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9795
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Space Outage (ft):	38.5162
Working Losses (lb):	915.1126

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Annual Net Throughput (gal/yr.):	28,800,000.0000
Annual Turnovers:	17.1400
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,680,000.0000
Maximum Liquid Height (ft):	38.5000
Tank Diameter (ft):	82.2300
Working Loss Product Factor:	1.0000

Total Losses (lb):	1,548.9604

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	915.11	633.85	1,548.96