ANNUAL PERMIT COMPLIANCE TEST REPORT

For

DUCT BURNER EMISSIONS

On a

COGENERATION UNIT CONSISTING OF A COMBINED-CYCLE GENERAL ELECTRIC LM 6000 PC SPRINT COMBUSTION TURBINE AND COEN DUCT BURNER SYSTEM

At the

UNIVERSITY OF FLORIDA COGENERATION PLANT

In

GAINESVILLE, ALACHUA COUNTY, FLORIDA

Prepared for the

FLORIDA POWER CORPORATION

October 2001

Cubix Job No. 6626-10

Prepared by

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INTRODUCTION

Emission testing was conducted on a combined-cycle 48-megawatt (MW) General Electric (GE) LM 6000 PC gas turbine generator set and associated duct burner system. The unit consists of a natural gas fueled combined-cycle combustion turbine directly coupled to a 60-Hertz generator. Combustion turbine exhaust is routed to a heat recovery steam generator (HRSG) that is equipped with a supplemental natural gas-fired Coen duct burner system. This cogeneration unit, used to generate both electrical power and process steam, is in service at the University of Florida Cogeneration Facility located in Gainesville, Alachua County, Florida. Florida Power Corporation (FPC), a Progress Energy Company, owns and operates this facility. Cubix Corporation, Southeast Regional Office conducted this testing on September 24th, 2001.

The purpose of this testing was to determine the status of annual compliance for duct burner emissions with the permit limits set forth by the Florida Department of Environmental Protection (FDEP) Title V Permit Number 0010001-001-AV. The tests followed the procedures set forth in 40 CFR 60, Appendix A, Methods 3a, 7e, 9, 10, and 19.

The combustion turbine exhaust was analyzed for oxides of nitrogen (NO_X), carbon monoxide (CO), and oxygen (O_2) using continuous instrumental monitors at a location prior to the duct burners. The combined combustion turbine and duct burner system exhaust was analyzed for CO and O_2 using continuous instrumental monitors at the HRSG stack. A certified observer determined visible emissions (VE) from the HRSG stack for the combined emissions. Additionally, the FPC continuous emissions monitoring system (CEMS) data for combined NO_X and CO_2 emissions were collected from the HRSG stack. Table 1 provides background data pertinent to these tests.

This test report has been reviewed and is approved for submittal by the following representatives:

Cubix Corporation	**Florida Power Corporation**

TABLE 1
BACKGROUND DATA

Owner/Operator:	**Florida Power Corporation** A Progress Energy Company 13th Avenue South, BB1A St. Petersburg, Florida 33701 Attn: J. Michael Kennedy, Air Program Supervisor (727) 826-4434 Phone (727) 826-4216 Facsimile Email: j-michael.kennedy@pgnmail.com
Testing Organization:	**Cubix Corporation, SE Regional Office** 3709 SW 42nd Avenue, Suite 2 Gainesville, Florida 32608 Attn: Leonard Brenner, Project Manager (352) 378-0332 Phone (352) 378-0354 Facsimile Email: lbrenner@cubixcorp.com
Test Participants:	**Florida Power Corporation** J. Michael Kennedy **Cubix Corporation** Leonard Brenner Roger Paul Osier
Test Dates:	September 24th, 2001
Regulatory Application:	The state regulations under Florida Department of Environmental Protection (FDEP) Title V Permit No. 0010001-001-AV apply.
Facility Location:	The FPC University of Florida Cogeneration Facility is located on Mowry Road at Building 82, University of Florida in Gainesville, Alachua County, Florida at postal code 32601 (UTM Coordinates: Zone 17, 369.4 km East and 3279.3 km North; Latitude: 29°38'23" North and Longitude: 82°20'55" West.)

Process Description: A cogeneration unit, consisting of a combined-cycle combustion turbine (CT) and a heat recovery steam generator (HRSG) equipped with a supplemental duct burner system, is used to generate electrical power and process steam. The CT, a General Electric Model LM 6000 PC gas turbine generator with Enhanced Sprint System, consists of a single-shaft gas combustion turbine directly connected to a 60 Hz power generator. CT exhaust gases are routed to an HRSG to recover waste heat from the combustion process. A Coen duct burner system is installed in the HRSG stack to boost the heat in the system, thus increasing steam production. The facility is designed to provide natural gas fuel to the combustion turbine and duct burners. The turbine uses steam injection to control NO_X emissions. The duct burner system uses low-NO_X burners to control NO_X emissions.

Emission Sampling Points: The combustion turbine has been designated in the permit as FDEP Emissions Unit (EU) ID No. 0010001-001-001. The combustion turbine emissions may be measured from one of two locations. The primary location is the HRSG stack. Four sample ports are located perpendicular to each other in the 117-inch diameter circular stack. However, these ports cannot be used to determine turbine emissions while the duct burner system is firing. The second location is the CT outlet. This consists of one port in the HRSG at a location prior to the duct burners and located near the center of the HRSG ductwork, see Appendix A for diagrams. Access to the sample ports was provided with a permanently installed platform and stairwell system.

The HRSG with the duct burner system has been designated in the permit as FDEP EU ID No. 0010001-001-002. Duct burner system emissions exhaust through the HRSG stack described above in combination with CT emissions, see Appendix A. Duct burner emissions were determined from the difference of the CT outlet emissions from the HRSG stack emissions. Access to the sample ports was provided with a permanently installed platform stairwell system, and ladder system.

<u>Test Methods:</u>

EPA Method 3a was used to measure HRSG stack and Duct Burner inlet oxygen (CO_2) concentrations.

EPA Method 7e was used to measure Duct Burner inlet oxides of nitrogen (NO_X) concentrations.

EPA Method 9 was used to determine HRSG stack visible emissions (VE) measurements determined as opacity from a certified observer.

EPA Method 10 was used to measure carbon monoxide (CO) concentrations.

EPA Method 19 was used for calculation of stack flow and pollutant mass emission rates.

Facility CEMS provided HRSG stack NO_X and carbon dioxide (CO_2) emissions

SUMMARY OF RESULTS

Florida Power Corporation owns and operates the University of Florida Cogeneration Facility in Gainesville, Florida. At this facility a cogeneration unit, consisting of a combined-cycle combustion turbine and HRSG with duct burner system, is used to generate electrical power and process steam. The State of Florida designates the combustion turbine as FDEP EU ID No. 0010001-001-001. The State of Florida designates the duct burner system as FDEP EU ID No. 0010001-001-002. Exhaust emissions from these units are the subject of this report.

The test matrix consisted of determining duct burner (DB) system emissions. The tests included measurements of HRSG stack emissions and CT outlet emissions. DB emissions were determined as the difference of the CT outlet emissions from the HRSG stack emissions. Cubix conducted three test runs at the maximum achievable DB system operational load. The CT was operated at a steady load during these tests. The HRSG stack was measured for CO and O_2 concentrations using continuous instrumental monitors. Additional HRSG stack measurements included NO_X and CO_2 concentrations using the facility CEMS. The CT outlet, prior to the DB system, was measured for NO_X, CO, and O_2 concentrations using continuous instrumental monitors. The test runs were 1 hour in duration for all gaseous constituents. A one-hour VE test was conducted coincident with one of the test runs.

Table 2, the executive summary, signifies the performance for the DB system during the testing. These performance results are an average of the three test runs. These emissions are compared to the applicable environmental regulations.

TABLE 2
Executive Summary

Parameter	FDEP EU ID No. 0010001-001-002 Duct Burner System	FDEP Permit Limits
Duct Burner Heat Input (MMBtu/hr, LHV)	107.6	187.0
Load (% of Capacity as Heat Input, LHV)	57.6%	na
NO_X (lbs/hr)	0.809	18.7
NO_X (lbs/MMBtu)	0.00668	0.10
NO_X (tons/yr, assumes 2628 hours per year)	1.06	24.6
CO (lbs/hr)	10.4	28.1
CO (lbs/MMbtu)	0.0873	0.15
CO (tons/yr, assumes 2628 hours per year)	13.7	36.9
Visible Emissions (% opacity)	0%	10%

Table 3 presents a detailed summary of the emissions testing. This tabular summary contains all pertinent operational parameters, CEMS data, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X emissions are reported in units of parts per million by volume (ppmv) on a dry basis, ppmv corrected to 15% excess O_2 for the CT only, pounds per hour (lbs/hr), and pounds per million British thermal units (lbs/MMBtu) of fuel burned for the DB system only. CO emissions are reported in units of ppmv, dry basis, ppmv corrected to 15% excess O_2 for the CT only, lbs/hr, and lbs/MMBtu of fuel burned for the DB system only.

Volumetric flow and mass emission rates were determined by stoichiometric calculations (EPA Method 19) based on measurements of diluent gas O_2 concentrations, published "F-factors", fuel heating values determined from fuel composition, and unit fuel flow rates. Examples of emission rate calculations and other calculations necessary for the presentation of the results of this section are contained in Appendix B.

A VE observer certified per EPA Method 9 by Eastern Technical Associates of Raleigh, North Carolina, performed visible emission observations on the HRSG stack. A one-hour visible emissions test run was conducted per permit requirements. VE were an average of 0% opacity in the highest six-minute average for each test and no VE greater than 0% opacity was observed during the tests.

Appendix A contains field data sheets and stack diagrams. Appendix B contains examples of all calculations necessary for the reduction of the data presented in this report. Appendix C contains the fuel analysis supplied by FPC and Cubix's fuel calculation worksheet. Quality assurance activities are documented in Appendix D. Certificates of calibrations are contained in Appendix E of this report. Appendix F contains the records of logged data in one-minute intervals used to record the NO_X, CO, and O_2 concentrations; it also includes a running and final average of raw data. Appendix G contains the "Visible Emissions Observation Forms" and the observer certifications. Appendix H contains the operational data and CEMS data provided by FPC during the test runs. The FDEP facility permit is presented in Appendix I for reference purposes.

TABLE 3
Summary of Results
Duct Burner Compliance Testing

Company: Florida Power Corporation
Plant: UF Cogeneration Facility
Location: Gainesville, Florida
Technicians: LJB, RPO
Sources: Unit 001, a GE LM6000 PC Combustion Turbine
Unit 002, Coen Duct Burner System

Date	9/24/01	9/24/01	9/24/01		
Start Time	9:35	11:05	12:20		
Stop Time	10:35	12:05	13:20		
Generator Active Power (MW)	36.51	36.21	36.22	*36.31*	
Duct Burner Load (% of full load = 187.0 MMBtu/hr, LHV)	55.1%	58.6%	59.0%	*57.6%*	
CEMS NO_x (ppmv, dry basis)	18.364	18.808	18.893	*18.688*	
CEMS CO_2 (% volume, dry basis)	4.264	4.321	4.334	*4.306*	
CEMS NO_x (ppmv @ 15% excess O_2)	14.67	14.66	14.70	*14.68*	
Fuel Heating Value (Btu/lb, Higher Heating Value)	1041	1041	1041	*1041*	
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8710	8710	8710	*8710*	
Duct Burner Fuel Flow (kSCFH)	110.08	117.08	117.83	*115.0*	
Duct Burner Heat Input (MMBtu/hr, HHV)	114.6	121.9	122.6	*119.7*	
Turbine Fuel Flow (kSCFH)	349.3	347.8	347.0	*348.0*	
Turbine Heat Input (MMBtu/hr, HHV)	363.6	362.0	361.1	*362.2*	
Total (Turbine + DB) Heat Input (MMBtu/hr, HHV)	478.1	483.9	483.7	*481.9*	
Atmospheric Pressure ("Hg)	29.86	29.86	29.84	*29.85*	
Temperature (°F): Dry bulb	82.8	86.4	90.2	*86.4*	
(°F): Wet bulb	77.1	77.9	78.2	*77.7*	
Humidity (lbs moisture/lb of air)	0.0183	0.0182	0.0176	*0.0180*	
NO_x (ppmv, dry basis)	18.17	18.23	18.23	*18.21*	
CO (ppmv, dry basis)	10.75	10.74	10.62	*10.70*	
O_2 (% volume, dry basis)	15.17	15.25	15.22	*15.21*	
CO (ppmv, dry basis)	23.69	22.82	22.28	*22.93*	
O_2 (% volume, dry basis)	13.39	13.35	13.39	*13.38*	
Turbine O_2 "F_d Factor" (SCFH, dry basis)	1.156E+07	1.166E+07	1.157E+07	*1.160E+07*	
HRSG Stack O_2 "F_d Factor" (SCFH, dry basis)	1.160E+07	1.167E+07	1.173E+07	*1.166E+07*	
NO_x (ppmv, dry @ 15% excess O_2)	**18.7**	**19.0**	**18.9**	***18.9***	**25.0**
NO_x (lbs/hr, from Turbine)	**25.1**	**25.4**	**25.2**	***25.2***	**39.6**
CO (ppmv, dry @ 15% excess O_2)	**11.1**	**11.2**	**11.0**	***11.1***	**36.0**
CO (lbs/hr, from Turbine)	**9.03**	**9.11**	**8.94**	***9.03***	**28.8**
NO_x (lbs/hr, from Duct Burner)	**0.354**	**0.814**	**1.26**	***0.809***	**18.7**
NO_x (lbs/MMBtu, from Duct Burners)	**0.00309**	**0.00668**	**0.0103**	***0.00668***	**0.10**
CO (lbs/hr, from Duct Burner)	**10.9**	**10.3**	**10.1**	***10.4***	**28.1**
CO (lbs/MMBtu, from Duct Burners)	**0.0956**	**0.0842**	**0.0820**	***0.0873***	**0.15**

PROCESS DESCRIPTION

Florida Power Corporation owns and operates the University of Florida Cogeneration Facility in Gainesville, Florida. A cogeneration unit consists of a combustion turbine connected to a HRSG with a supplemental DB system. This unit produces both electrical power and process steam. Emission testing was conducted on the unit to determine the compliance status of the DB system with state regulations. This section of the test report provides a brief description of the cogeneration unit.

This cogeneration unit is designed to produce a nominal 48 MW of electrical power. The main body of the CT section consists of single shaft General Electric Frame LM 6000 PC gas turbine generator set directly coupled to a 60 Hz synchronous generator. The CT is equipped with evaporative coolers to drive the inlet air temperature down and an Enhanced Sprint System, Model 191-315, to inject water mist into the turbine air inlet. This ancillary equipment increases power output of the CT. The FDEP permitted capacity for the CT section is 399 MMBtu/hr based upon the lower heating value (LHV) of heat input firing with natural gas fuel. The CT is also permitted to operate while firing with No. 2 distillate fuel oil but does not do so at this time. The CT uses steam injection to control NO_X emissions. The State of Florida designates the CT section of this cogeneration unit with FDEP E.U. ID No. 0010001-001-001.

The cogeneration unit is also designed to produce process steam used by the CT and other facilities at the University of Florida. The CT exhaust is routed to a heat recovery steam generator. The HRSG is equipped with a supplemental Coen duct burner system to maximize steam production. The FDEP permitted capacity for the DB section is 187 MMBtu/hr (LHV) of heat input firing with natural gas fuel. The Coen DB system uses low-NO_X burners to control NO_X emissions. The State of Florida designates the DB section of this cogeneration unit with FDEP E.U. ID No. 0010001-001-002.

CT and DB exhaust gases are vented to the atmosphere through the HRSG stack that is a 92.5-foot tall circular stack. The sampling ports are approximately 29 feet (~ 3.0 stack diameters) downstream from the nearest flow disturbance, the HRSG outlet and approximately 10.5 feet (~ 1.1 stack diameters) upstream from the nearest flow disturbance, the stack outlet. Access to the stack was made available via a permanent steel frame platform equipped with a caged safety ladder and a stairwell system. The internal diameter of the stack at the sample port location was 117 inches. In addition, a sampling location in the beginning of the HRSG and before the DB system was used to sample CT only exhaust gases. This 2-inch diameter sample port was located near the center of the HRSG duct. Access to this sample location was made available via a permanent steel frame platform equipped with a stairwell system.

FPC personnel obtained operational data from control panel instrumentation. Data was collected from the control system in approximate 15-minute intervals and averaged over each test run. In addition, CEMS data was collected in one-minute intervals into an electronic file and averaged using a spreadsheet program over each test run. All operational data sheets are located in Appendix H.

ANALYTICAL TECHNIQUES

Emissions from a cogeneration unit were measured at the University of Florida Cogeneration Facility located in Gainesville, Florida. Cubix Corporation performed these tests on September 24, 2001 in order to determine the status of duct burner system emissions with regard to permitted emission limits. This section of the report describes the analytical techniques and procedures used during these tests.

The sampling and analysis procedures used during these tests conformed with those outlined in The Code of Federal Regulations, 40 CFR 60, Appendix A, Methods 3a, 7e, 9, 10, and 19. The CT outlet gas analyses for NO_X, CO, and O_2 were performed using continuous instrumental monitors. The HRSG stack gas analyses for CO and O_2 were performed using continuous instrumental monitors. Exhaust gas analyses were performed on a dry basis for all compounds. Table 4 lists the instruments and detection principles used for these analyses.

The test matrix for the DB system consisted of three sixty-minute test runs at the maximum achievable load on the DB and at steady state CT operation. HRSG stack gases were analyzed for CO and O_2 by System B continuous instrumental monitors during each test run while NO_X gas concentrations were supplied by the facility CEMS. Additionally, NO_X, CO, and O_2 concentrations were continuously monitored during each test run at the CT outlet by System A. DB system emissions were determined from the difference of the CT emissions from the HRSG stack emissions. A 60-minute VE test was conducted concurrently with one of the test runs.

Provisions were made to introduce the calibration gases to the instrumental monitors via two paths: 1) directly to the instruments via the sample manifold quick-connects and rotameters, and 2) through the complete sampling system including the sample probe, filter, heat trace, condenser, manifold, and rotameters. The former method was used for quick, convenient calibration checks. The latter method was used to demonstrate that the sample was not altered due to leakage, reactions, or adsorption within the sampling system (sample system bias check). A NO_X standard calibration gas was introduced into the NO_X analyzer directly. Then the response from the NO_X analyzer was noted as the calibration gas was introduced at the probe. Any difference between the two responses in the instrument was attributed to the bias of the sample system. Following the span gas bias check, a zero gas bias check was performed on the NO_X analyzer using nitrogen, or another calibration gas as a zero, to check for any zero bias of the sample system. In accordance with EPA Method 3a this span and zero bias check procedure was repeated for the CO_2 and O_2 analyzers. This procedure was also used for CO although not required by the EPA method.

Figure 1 shows the set-up for sampling the CT outlet and HRSG stack with the continuous instrumental monitors. The CT outlet gas sample was continuously pulled through a 1-inch diameter Inconel (a high temperature resistant steel) probe and transported via a 100 foot long, $^3/_8$-inch diameter heat-traced Teflon® line into the mobile laboratory using a stainless steel/Teflon® diaphragm pump. At the pump exit the pressurized sample was pushed into a heated sample manifold. The bulk of the gas stream then passed to a stainless steel minimum contact condenser to dry the sample stream and into the System A (dry) sample manifold. From the System A manifold, the sample was partitioned to the analyzers through glass and stainless steel rotameters for flow control of the sample. The HRSG stack gas sample was continuously pulled through a 1-inch diameter stainless steel probe and transported via 30-foot long, $^3/_8$-inch diameter heat-traced Teflon® tubing to a stainless steel minimum contact condenser to dry the sample stream. The HRSG stack sample was then transported along a 100-foot long, 3/8-inch diameter sample line into the mobile laboratory through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the (dry) sample manifold. The bulk of the gas stream then passed to and into the System B sample manifold. From the System B manifold, the sample was partitioned to the System B analyzers through glass and stainless steel rotameters for flow control of the sample.

All instruments were housed in an air-conditioned trailer-mounted mobile laboratory. Gaseous calibration standards were provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 was used to determine the cylinder concentrations where applicable (i.e., NO_X calibration gases).

The HRSG stack and CT outlet gas analyses for O_2 concentrations were performed in accordance with procedures set forth inE PA Method 3a. Instrumental analyses were used in lieu of an Orsat or a Fyrite procedure due to the greater accuracy and precision provided by the instruments. Each O_2 analyzer operated using a current generating micro-fuel cell.

Each O_2 analyzer had slightly different reading for the same low-level and mid-level calibration gases. Minute difference in readings, ~ 0.1% volume, between measured O_2 concentrations the HRSG stack and CT outlet could result in large differences in emissions. In order to obtain more consistent readings between the analyzers, second order polynomial calibration curves were developed for each O_2 analyzer. These correction curves were used on all effluent emission data and calibration data for these tests.

EPA Method 7e procedures were used to determine CT outlet concentrations of NO_X (via chemiluminescence). NO_X mass emission rates were calculated as if all the NO_X was in the form of NO_2. This approach corresponds to EPA's convention, however, it tends to overestimate the actual NO_X mass emission rates since the majority of NO_X is in the form of NO which has less mass per unit volume (i.e., lbs. of emissions per ppmv concentration) than NO_2.

Opacity was determined via EPA Method 9. A one-hour opacity test run was performed on the HRSG stack by a visible emissions observer who was certified by Eastern Technical Associates of Raleigh, North Carolina. Appendix G provides both the opacity observation sheets as well as observer certification documentation.

HRSG stack and CT outlet CO emission concentrations were quantified in accordance with procedures set forth in EPA Method 10. Continuous non-dispersive infrared (NDIR) analyzers were used for this purpose. These reference method analyzers were equipped with a gas correlation filter that removes most interference from moisture, CO_2, and other combustion products.

The facility contains a continuous emissions monitoring system (CEMS). This system monitors HRSG stack emissions for NO_X and CO_2 to demonstrate continuous compliance with the permit for CT emissions when the duct burners are off and for combined CT + DB emissions when the duct burners are on. Raw NO_X data from the CEMS in ppmv, along with NO_X measured by Cubix in the CT outlet, was used in determination of DB NO_X emissions.

All data from the continuous monitoring instruments were logged into an electronic file in one-minute intervals. A data logger with a computer generated display screen monitored, recorded and averaged the emission concentrations. The program controlling the logging of data was also used to log QA data. See Appendix F of this report for copies of the raw data and Appendix D for the QA data.

The stoichiometric calculations of EPA Method 19 were used to calculate the HRSG stack and CT outlet volumetric flow rates and mass emission rates. These calculations are based on the heating value and the O_2 "F-factor" (DSCF of exhaust per MMBtu of fuel burned) for natural gas. Method 19 flow rate determinations are also based on the excess air (as measured from the exhaust diluent concentrations) and the fuel flow rates.

Cubix personnel collected ambient absolute pressure, temperature, and humidity data during each test run. A wet bulb/dry bulb sling psychrometer was used to determine ambient temperature and humidity conditions. An aircraft-type aneroid barometer (altimeter) was used to measure atmospheric pressure.

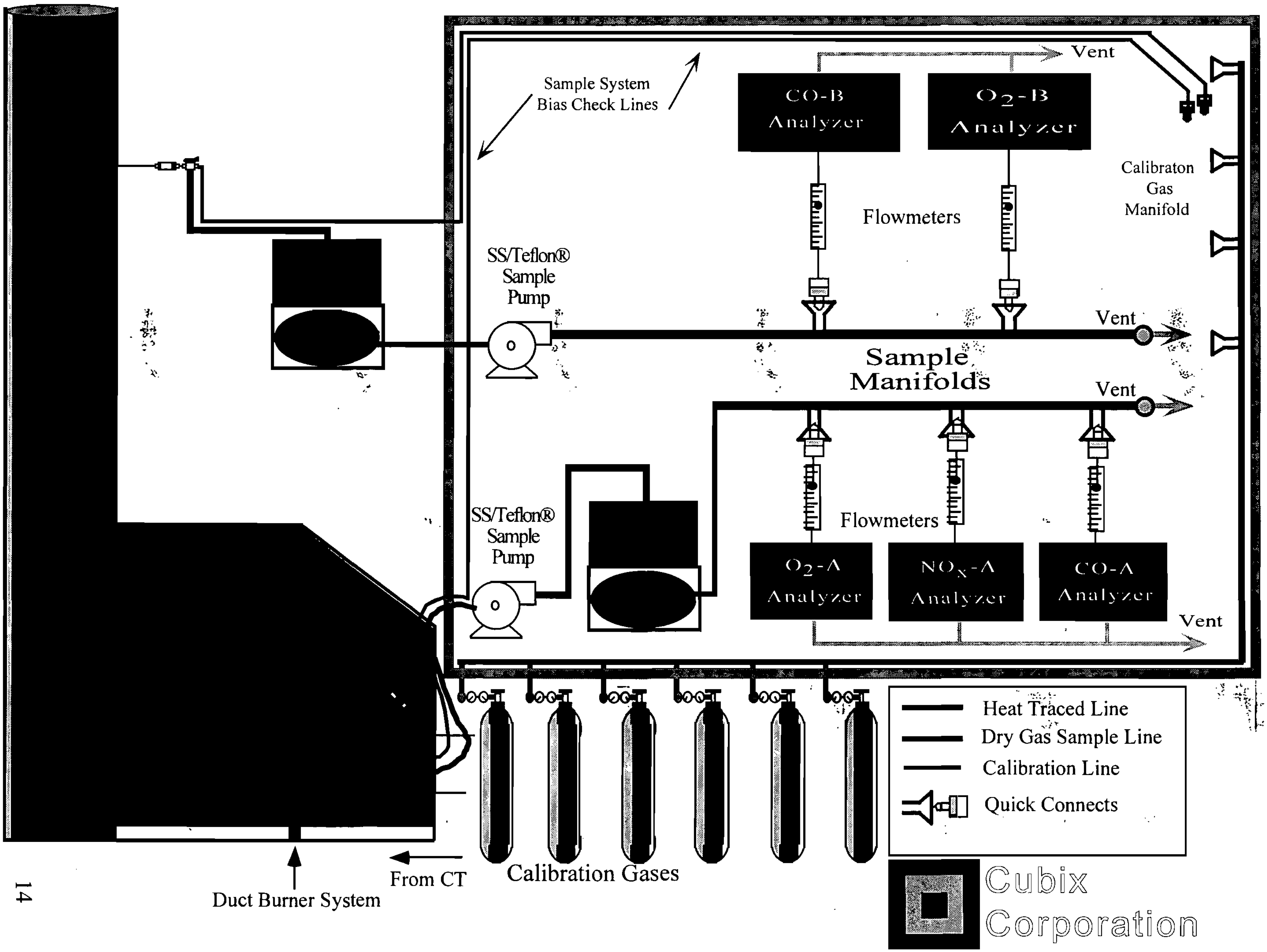
All emission calculations were conducted by a computer spreadsheet as shown in Tables 2and 3of this report. Example calculations were performed manually using a hand-held calculator in order to verify the spreadsheet formulas. Example calculations are in Appendix B of this report.

TABLE 4
ANALYTICAL INSTRUMENTATION

Parameter	Model and Manufacturer	Common Use Ranges	Sensitivity	Response Time (sec.)	Detection Principle
NO_X	TECO Model 42C (Sys A)	0-10 ppmv 0-30 ppmv 0-50, 0-100 ppmv 0-200, 500 ppmv 0-1,000 ppmv 0-5,000 ppmv	0.1 ppmv	1.7	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear within 1% of full scale.
CO	TECO Model 48 (Sys-B) Model 48C (Sys-A)	0-1 ppmv 0-10 ppmv 0-30 ppmv 0-50, 0-100 ppmv 0-200, 0-500 ppmv 0-1000 ppmv	0.1 ppmv	60	Infrared absorption, gas filter correlation detector, micro-processor based linearization.
O_2 (Sys A)	Teledyne Model 320 AR	0-5% 0-10% 0-25%	0.025% 0.05% 0.125%	15	Micro-fuel cell with amperometric detector, inherently linear.
O_2 (Sys B)	Teledyne Model 320 A	0-5% 0-10% 0-25%	0.025% 0.05% 0.125%	15	Micro-fuel cell with amperometric detector, inherently linear.

NOTE: Higher ranges available by sample dilution.
Other ranges available via signal attenuation.

FIGURE 1
INSTRUMENTAL SAMPLE SYSTEM DIAGRAM



QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities were undertaken before, during, and after this testing project. This section of the report combined with the documentation in Appendices D and E describe each of those activities.

A multi-point calibration was performed for each instrument in the field prior to the collection of data. The instrument's linearity was checked by first adjusting the instrument's zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response was then challenged with other calibration gases of known concentration. The instrument's response was accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range from the predicted values. The response of the infrared absorption type CO analyzers is made linear through electronic suppression.

System bias checks were performed both before and after the sampling system was used for emissions testing. The sampling system's integrity was tested by comparing the responses of the NO_X analyzer to a calibration gas (and a zero gas) introduced via two paths as previously described in the *Analytical Techniques* section of this report. This system bias test was performed to assure that no alteration of the sample had occurred during the test due to leakage, reactions, or absorption. Similarly, system bias checks were performed with CO and O_2 for added assurance of sample system integrity. The results of the system bias checks are available in Appendix D.

The efficiency of the NO_2 to NO converter in the NO_X analyzer was checked by monitoring a mixture of NO in N_2 standard gas and zero grade air from a Tedlar® bag. When this bag is mixed and exposed to sunlight, the NO is oxidized to NO_2. If the NO_X instrument's converter is 100% efficient, then the total NO_X response does not decrease as the NO in the bag is converted to NO_2. The criterion for acceptability is demonstrable NO_X converter efficiency greater than 90%; this is demonstrated if the concentration of NO_X does not decrease by more than 2% of the highest read value over a 30-minute period. Quality assurance worksheets, found in Appendix D, summarize the results of the converter efficiency test.

The residence time of the sampling and measurement system was estimated using the pump flow rate and the sampling system volume. The pump's rated flow rate is 0.8 scfm at 5 psig. The sampling system volume was approximately 0.175 scf. Therefore, the minimum sample residence time was ~ 13 seconds.

Cubix Corporation and instrument vendors conducted interference response tests on the NO_X, CO, and O_2 analyzers. The sum of the interference responses for

H_2O, C_3H_8, CO, CO_2 and O_2 is less than 2 percent of the applicable full-scale span value. The instruments used for the tests meet the performance specifications for EPA Methods 3a, 7e, 10, and 20. The results of the interference tests are available in Appendix D of this report.

Both sampling systems, System A and System B, were leak checked by demonstrating that they could each hold a vacuum greater than 15 inches of mercury ("Hg) (>21 "Hg actual) for at least 1 minute with a decline of less than 1 "Hg. A leak test was conducted both after the sample system was set up before testing began and after testing was completed before the system was dismantled. This test was conducted to insure that ambient air was not diluting the sampling system. No leakage was detected.

As a minimum, before and after each test run, the analyzers were checked for zero and span drift. This allows test runs to be bracketed by calibrations and documents the precision of the data just collected. Calibration gases were introduced to the analyzers through the entire sampling system. Appendix D contains quality assurance tables that summarize the zero and span checks that were performed for each test run. The worksheets also contain the data used to correct the data for drift per EPA Method 6c, Equation 6c-1. NO_X and O_2 data were corrected for drift as required by the test methods. Although not required by the test methods, CO concentrations were also corrected for drift toma intain consistency in results reporting.

The control gases used to calibrate the instruments were analyzed and certified by the compressed gas vendors to ±1 % accuracy for all calibration gases. EPA Protocol No. 1 was used, where applicable (i.e., NO_X gases), to assign the concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials (SRM's). The gas calibration sheets as prepared by the vendor are contained in Appendix E.

Cubix collected and reported the enclosed test data in accordance with the procedures and quality assurance activities described in this test report. Cubix makes no warranty as to the suitability of the test methods. Cubix assumes no liability relating to the interpretation and use of the test data by others.

UF Cogeneration Facility
New Coen Duct Burner
Emissions Tuning Results

Company: Florida Power Corporation
Plant: UF Cogeneration Facility
Location: Gainesville, Florida
Technicians: LJB, RPO
Sources: Unit 001, a GE LM6000 PC Combustion Turbine
Unit 002, Coen Duct Burner System

Date	4/29/02	4/29/02	4/29/02	4/29/02	4/29/02	
Start Time	11:15	12:10	12:52	13:27	14:02	
Stop Time	11:30	12:24	12:59	13:40	14:14	
Generator Active Power (MW)	45.9	46.0	45.9	46.2	46.1	
Duct Burner Load (% of full load = 187.0 MMBtu/hr, LHV)	0.0%	13.2%	23.3%	28.1%	39.4%	
Number of Burners Firing	0	2	4	4	6	
Fuel Heating Value (Btu/lb, Higher Heating Value)	1041	1041	1041	1041	1041	
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8710	8710	8710	8710	8710	
Duct Burner Fuel Flow (kSCFH)	0.0	26.3	46.6	56.1	78.6	
Duct Burner Heat Input (MMBtu/hr, HHV)	0.0	27.4	48.5	58.4	81.8	
Duct Burner Heat Input (MMBtu/hr, LHV)	0.0	24.6	43.6	52.5	73.6	
Turbine Fuel Flow (kSCFH)	420.6	419.3	418.8	421.0	418.5	
Turbine Heat Input (MMBtu/hr, HHV)	437.7	436.4	435.9	438.2	435.6	
Total (Turbine + DB) Heat Input (MMBtu/hr, HHV)	437.7	463.8	484.4	496.5	517.4	
Atmospheric Pressure ("Hg)	29.93	29.91	29.89	29.88	29.87	
Temperature (°F): Dry bulb	87.0	88.0	89.5	92.0	92.8	
(°F): Wet bulb	73.0	74.0	74.3	74.8	75.0	
Humidity (lbs moisture/lb of air)	0.0138	0.0144	0.0143	0.0141	0.0141	
NO_X (ppmv, dry basis)	20.69	18.30	18.21	18.44	18.37	
CO (ppmv, dry basis)	15.60	22.94	23.13	22.44	22.48	
O_2 (% volume, dry basis)	14.76	14.74	14.71	14.70	14.70	
NO_X (ppmv, dry basis)	21.14	19.05	19.09	19.57	20.30	
CO (ppmv, dry basis)	15.62	24.70	28.31	27.26	26.09	
O_2 (% volume, dry basis)	14.65	14.33	14.00	13.82	13.48	
Turbine O_2 "F_d Factor" (SCFH, dry basis)	1.298E+07	1.290E+07	1.282E+07	1.286E+07	1.279E+07	
HRSG Stack O_2 "F_d Factor" (SCFH, dry basis)	1.275E+07	1.285E+07	1.278E+07	1.277E+07	1.269E+07	
NO_X (ppmv, dry @ 15% excess O_2)	**19.9**	**17.5**	**17.4**	**17.5**	**17.5**	**25**
NO_X (lbs/hr, from Turbine)	**32.1**	**28.2**	**27.9**	**28.3**	**28.0**	**39.6**
CO (ppmv, dry @ 15% excess O_2)	**15.0**	**22.0**	**22.0**	**21.4**	**21.4**	**36**
CO (lbs/hr, from Turbine)	**14.7**	**21.5**	**21.6**	**21.0**	**20.9**	**28.8**
NO_X (lbs/hr, at HRSG Stack)	**32.2**	**29.2**	**29.1**	**29.8**	**30.8**	
NO_X (lbs/hr, from Duct Burner)	**na**	**1.05**	**1.26**	**1.51**	**2.71**	**18.7**
NO_X (lbs/MMBtu, from Duct Burners)	**na**	**0.038**	**0.026**	**0.026**	**0.033**	**0.1**
CO (lbs/hr, at HRSG Stack)	**14.5**	**23.1**	**26.3**	**25.3**	**24.1**	
CO (lbs/hr, from Duct Burner)	**na**	**1.57**	**4.75**	**4.32**	**3.18**	**28.1**
CO (lbs/MMBtu, from Duct Burners)	**na**	**0.057**	**0.098**	**0.074**	**0.039**	**0.15**

University of Florida Co-Generation Facility
The "How, When & Why" of Duct Burner Operation

The facility typically operates the GE LM6000-SPRINT combustion turbine at approximately 95% of load at all times, with the exceptions being during start-ups, shutdowns, malfunctions and outages. The combustion turbine is exhausted through the heat recovery steam generator (HRSG) to generate steam for the University, hospitals and their associated facilities. The steam generated by the HRSG is provided on an as-needed basis; i.e., when the steam demand is present. If there is no steam demand or steam demand is less than the steam generated by the HRSG from the combustion turbine exhaust, the excess steam is "wasted" or vented. Therefore, the greatest quantity of steam is "wasted" or vented when ambient temperatures are the warmest.

Alternatively, the peak steam demand from the University, hospitals and associated facilities typically coincides when ambient temperatures are coldest. However, if the HRSG cannot meet the steam demand with steam generated solely from the combustion turbine exhaust, supplemental heat input is provided by the duct burner. In response to the steam demand, up to ten (10) different levels of burners will fire. Each level of burner either operates at 100% of its capacity or does not operate at all; there is no partial firing of individual burners or burner levels. Furthermore, the duct burner cannot operate independently of the combustion turbine; i.e., the facility is incapable of operating with just the duct burner firing, the combustion turbine must be fired in conjunction with the duct burner.

When steam demand requires firing of the duct burner the heat input (in mmBtu/hour) to the duct burner will fluctuate to control HRSG superheater outlet pressure; i.e., rise and fall, during any given time the duct burner is operating. This fluctuation or variation in heat input can be extensive. With the inherent limitations on the operation of the duct burner there are several obstacles to conducting testing that would meet the letter of Chapter 62 of the Florida Administrative Code (F.A.C.). The FAC requires operating the duct burner at 90% of the permitted heat input or limit the heat input to the duct burner by testing at a lower rate, thereby limiting the duct burner to 110% of the heat input at which it was tested. In addition, if the unit exceeds the self-imposed heat input limit, PEF is required by rule (62-297.310(2), F.A.C.) to conduct testing within 15 days of exceeding the testing-imposed heat input limit. This would require that the unit be re-tested within 15-days and to accomplish testing at the higher heat input would require a greater steam demand (i.e., typically colder temperatures) than operating mode during which the testing-imposed limit was exceeded. If the steam demand was less than required, it would require venting or "wasting" steam, burning fuel unnecessarily and generating unnecessary emissions. Further, the venting itself represents a safety issue In addition, providing appropriate test notifications would prove problematic given the inability to predict the weather and adequately schedule stack test teams. The result would be the reliance on enforcement discretion from the compliance authority regarding test notifications; PEF prefers not to rely on enforcement discretion and would prefer to address this situation through the permitting process.

University of Florida Co-Generation Facility
Explanation of Combustion Turbine Routine Maintenance Schedule

The following is a brief description of recommended maintenance intervals for the General Electric (GE) manufactured LM6000 combustion turbine. At each inspection and major maintenance interval, all GE-required maintenance requirements are followed and any GE Technical Bulletins that require action are implemented as part of next scheduled inspection or maintenance interval.

The GE maintenance intervals and brief description are as follows:

1. **4,000-Hour Maintenance**

   At each Spring and Fall outage, Progress Energy Florida, Inc. (PEF) performs normal routine/preventative maintenance (PM) on the engine, enclosure for the engine and generator that includes piping, engine supports, instrumentation, cooling fans, pumps, hydraulic starting equipment, ductwork, auxiliary systems, etc. This maintenance includes an overall inspection, boroscope and appropriate maintenance of the engine.

2. **25,000-Hour Maintenance**

   The GE LM6000 engine requires significant routine maintenance every 25,000 hours of operation. An element of the required 25K-hour maintenance is a "hot section" exchange. The "hot section" exchanges include a like-kind replacement of the combustor, high-speed turbine including blades, nozzles and other components. The replacements are either new or refurbished like-kind parts to restore the components to the Original Equipment Manufacturer (OEM) specifications.

3. **50,000-Hour Maintenance**

   At this maintenance interval a major overhaul of the unit is conducted and, in addition to the following, includes the 25,000-hour interval maintenance items. In addition to the "hot section" exchange, it also includes inspecting every engine component, refurbishing and returning the component to original like-kind OEM specifications. This includes the high and low-speed compressors and turbines.

At each inspection and major maintenance, all required GE maintenance requirements are followed. Any GE technical bulletin that requires action is implemented as part of any inspection or maintenance interval. The replacements are either new or refurbished to bring the components back to Original Equipment Manufacturer (OEM) specifications.

University of Florida Co-Generation Facility
Summary of Permitting History

PSD Permit No. PSD-FL-181 & initial Air Construction Permit No. AC01-204652: Issued on August 17, 1992 authorized the construction of a 43 MW co-generation facility at the University of Florida, in part, to replace Boilers Nos. 1, 2 & 3. The permit expired on December 31, 1994. Highlights include

1. A Combustion Turbine (CT) in conjunction with a Heat Steam Recovery Generator (HRSG) and duct burner was installed to replace three (3) boilers. The Ct was a LM6000 from General Electric (GE) and the HRSG was by Deltak and included a Duct Burner manufactured by Coen.

2. PSD analysis indicated that the BACT was applicable to carbon monoxide (CO).

3. The CO limit for the

    a. combustion turbine was 42 ppmvd on gas (BACT & basis of limit), 38.8 lbs/hr and 158 TPY. Limited to 8,147 hours/ year on natural gas.

    b. duct burner was 0.15 lb/mmBtu (BACT & basis of limit), 28.1 lbs/hour and 36.9 TPY. Limited to 2,628 hours/year of operation.

4. Combustion turbine was authorized to operate up to 219 hour/year on No. 2 fuel oil; however, and additional 1.9 hours/year operation on natural gas was allowed each 1.0 hour/year that fuel oil is not burned up to 416 hours (i.e., 219 hours X 1.9). Natural gas combustion emission limits were to be "adjusted accordingly".

5. Total NOx emissions for the facility were capped at 194.3 TPY.

Permit Nos. PSD-FL-181(A)/AC01-204652: Issued on September 11, 1997 as an amendment to the original PSD and AC permits. Highlights include

1. The lbs/hr limit for NOx from the combustion turbine was increased from 35.0 to 39.6 lbs/hr. This action was taken to allow for a requested increase in heat input to the CT at ambient temperatures near 45 °F and a corresponding increase in short-term NOX emission in lbs/hour). There was no corresponding increase in the annual NOx emissions in TPY authorized.

Permit No. 0010001-001-AV: Issued on January 01, 2000 as the initial Title V permit. Highlights include

1. The basis of limit for CO for the combustion turbine operating on natural gas remains at 42 ppmv (BACT) and the allowable limits are 38.8 lbs/hr and 158.0 TPY.

2. The basis of limit for the CO from the duct burner remains at 0.15 lb/mmBtu (BACT) and the allowable limits are 28.1 lbs/hr and 36.9 TPY.

3. The facility NOx emissions cap remained at 194.3 TPY. The combustion turbine is limited to 39.6 lbs/hr and 142.7 TPY with the basis of these limit being 25 ppmvd. Limits are based on a 30-day rolling average.

Permit No. 0010001-002-AC: This permit was never issued and no documents are posted on the DEP's "Permit Document Search" webpage.

Permit No. 0010001-003-AC: Issued on May 18, 2001 authorized the replacement of the 43 MW GE LM6000 combustion turbine with a new 48 MW model incorporating the SPRay INTercooling ("SPRINT") technology. Due to the combustion characteristics of the replacement combustion turbine, CO emission will be lowered and limited to 36 ppmvd for natural gas. This results in a decrease in the allowable CO emission from 158 TPY to 127.5 TPY. Highlights include

1. Authorized the replacement of the GE LM6000 Combustion turbine with the GE LM6000-SPRINT model.

2. PSD review and a BACT determination were <u>NOT REQUIRED</u> for this project since the net emissions increases are less than the PSD Significant Emission Rate (SER) for all pollutants.

3. The combustion turbine/duct burner operation at maximum firing rates shall be limited to 7,211 hours per year (to prevent retroactive PSD applicability for NOx under PSD-FL-181 by reaching the 40 tons per year PSD applicability threshold). The turbine/duct burner may operate at lower than maximum rates for more hours per year provided that the annual fuel consumption limitations are not exceeded, i.e., total annual fuel usage for the combustion turbine and the duct burner combined shall not exceed 3.48 trillion Btu.

4. Hours of Operation/Fuel Usage Limitations: Combustion turbine/duct burner operation at maximum firing rates shall be limited to 7,211 hours per year (to prevent retroactive PSD applicability for NOx under PSD-FL-181, pursuant to Rule 62-212.400(5), F.A.C., by reaching the 40 tons per year PSD applicability threshold). The turbine/duct burner may operate at lower than maximum rates for more hours per year provided that the annual fuel consumption limitations are not exceeded and that facility-wide NOx emissions do not exceed 194.3 TPY. The total annual fuel usage for the combustion turbine and the duct burner combined shall not exceed 3.48 trillion BTU (includes up to 635,100 gallons No. 2 fuel oil fired in the turbine). The annual fuel usage by the duct burner is limited to 519.5 million ft natural gas.

5. PSD analysis was conducted and the NOx emission increase was 39.5 TPY; below the Significant Emission Rate (SER) of 40 TPY.

6. Total NOx emissions from the CT/HRSG configuration were capped at 141 TPY and 25 ppmvd on a 30-day rolling average. The 141 TPY NOx cap on the CT/HRSG s was at the request of Florida Power Corporation (FPC) to avoid PSD.

7. PSD analysis was conducted and the CO emission increase was 96.1 TPY; below the Significant Emission Rate (SER) of 100 TPY.

8. Total CO emissions from the CT/HRSG configuration shall not exceed 36 ppmvd (decreased from 42 ppmvd), 35.8 lbs/hr (decreased from 38.8 lbs/hr) and 127.5 TPY (decreased from 158.0 TPY). This was at the request of Florida Power Corporation (FPC) to avoid PSD.

9. CO emissions from the DB shall not exceed 0.15 lb/mmBtu, 28.1 lbs/hr and 39.6 TPY.

Permit No. 0010001-004-AC: Requested modification of 0010001-003-AC. Highlights include

1. Heat input for the combustion turbine while firing natural gas was increased from the current 392 mmBtu/hour to 408 mmBtu/hour; both heat inputs are reference to 59 °F and the Lower Heating Value (LHV) of the natural gas. The permit now only references "The values indicated on the turbine manufacturer's heat input vs. power output curve attached to this permit (Attachment C)."

2. The combustion turbine limit on total NOx emissions remains at 141 TPY.

Letter Amendment to Permit No. 0010001-004-AC: Issued on March 27, 2003 authorized the extension of permit expiration date for permit No. 100010001-003-AC, extending the expiration date from December 31, 2002 to December 31, 2003.

Permit No. 0010001-006-AC: Issued on October 9, 2003 and amended permit No. 0010001-004-AC. Essentially Progress Energy requested a revision to reduce of the combustion turbine short-term CO limits to avoid New Source Review (NSR). Highlights include

1. CO emissions from the CT shall not exceed 31.6 ppmvd (decreased from 36 ppmv), 29.9 lbs/hr (decreased from 35.8 lbs/hr) and 127.5 TPY (remained unchanged). This appears to be the result of a request for increase in annual hours of operation; that is,

   (127.5 TPY)(1 ton/2,000 lbs) / (8,541 hours/year) = 29.86 lbs/hr = 29.9 lbs/hr

2. The combustion turbine and duct burner are allowed to operate continuously (i.e., 8,760 hrs/yr) while firing natural gas. At the maximum firing rate, the CT is limited to firing No. 2 fuel oil for 219 hours/year; that is,

   (8,760 hours/year – 8,541 hours/year) = 219 hours/year

3. Remaining changes are associated with NOx emissions.

Permit No. 0010001-005-AV: This revision to the Title V permit was issued January 05, 2004. The revision included the incorporation of the following permits into the Title V Air Operating Permit:

1. Permit No. 0010001-003-AC
2. Permit No. 0010001-004-AC

3. Permit No. 0010001-006-AC

Permit No. 0010001-007-AV: Renewal of Permit number 0010001-005-AV was issued with an effective date of January 01, 2005. Highlights include

1. The allowable CO limits for combustion turbine remain unchanged at 31.6 ppmv, 29.9 lbs/hr and 127.5 TPY.

2. The allowable CO limit for duct burner remains at 0.15 lb/mmBtu, 28.1 lbs/hr and 36.9 TPY.

3. The combustion turbine and duct burner continue to be allowed to operate continuously (i.e., 8,760 hrs/yr) while firing natural gas. At the maximum firing rate, the CT is limited to firing No. 2 fuel oil for 219 hours/yr.

4. For "Permitted Capacity" the permit references a heat input vs. power output curve; specifically, "....the attached GE Curves Corrected for Site Conditions"

Permit No. 0010001-008-AV: Revision of Permit No. 0010001-007-AV was issued on March 24, 2009 and was issued to include the requirements and conditions of the Clean Air Interstate Rule (CAIR) in the Title V Operating Permit.

Permit No. 0010001-009-AV: Renewal of Permit No. 0010001-008-AV with an effective date of January 01, 2010; this is the current Title V permit the facility is operating under. Highlights include:

1. The combustion turbine and duct burner continue to be allowed to operate continuously (i.e., 8,760 hrs/yr) while firing natural gas. At the maximum firing rate, the CT is limited to firing No. 2 fuel oil for 219 hours/yr.

2. The allowable CO limit for combustion turbine remains at 31.6 ppmv, 29.9 lbs/hr and 127.5 TPY.

3. The allowable CO limits for duct burner remain unchanged at 28.1 lbs/hr and 36.9 TPY. The value of 0.15 lb/mmBtu returns to being the basis of limit.

YEAR	OPERATED HOURS
2005	8,053
2006	7,817
2007	7,561
2008	7,419
2009	7,255
Minimum	7,255
Average	7,621
Median	7,561
Maximum	8,053