# WEST COUNTY POWER PARTNERS, LLC

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Florida Power & Light Company
West County Energy Center – Units 1&2
Permit No. – PSD-FL-354
DEP File No. – 0990646-001-AC

WCPP Project 144553
WCPP Files 14.0200/32.0440
WCPP-2009-TP-0575
November 19, 2009
E-mail, Express Mail



Ms. Elizabeth Walker
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Bureau Chief
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Subject: **West County Units #1 and #2 Fuel Oil Air Permit Compliance Test Protocol**

Dear Ms. Walker:

On behalf of Florida Power & Light Company (FPL) and its Designated Representative, Sheila M. Wilkinson, the West County Power Partners, LLC (WCPP), EPC Contractor for construction of the new combined cycle generating Unit 1 and 2 at the FPL West County Energy Center, is submitting the Fuel Oil Air Permit Compliance test protocol in accordance with 40 CFR Part 60.8 and the State of Florida Conditions of Certification Air Permit regulations. In addition, the purpose of this letter is to provide a test schedule which is detailed in Table 1.

Table I. Dates for initial start up activities at West County Energy Center Units 1 & 2.

| Units | Performance Emission Test | Opacity Observations |
|---|---|---|
| CT 1A | February 8, 2010 | February 8, 2010 |
| CT 1B | January 19, 2010 | January 19, 2010 |
| CT 1C | January 21, 2010 | January 21, 2010 |
| CT 2A | March 31, 2010 | March 31, 2010 |
| CT 2B | April 2, 2010 | April 2, 2010 |
| CT 2C | April 4, 2010 | April 4, 2010 |
| | 60.8 (d) & PSD Permit Standard Condition #22 | 60.7(a)(6), 60.11(b)& 60.7(a)(7) |

Please note that the dates provided in Table I are subject to change. As the start-up activities occur, WCPP will update FDEP of new revised dates when they are available. Please note that this notice is one of many notifications for West County Energy Center Units 1 & 2.

If you have any questions about this notification or the attachment, please contact Terry Apple at (913) 458-7220 or John Tidwell at (561) 784-8048.

Very truly yours,

WEST COUNTY POWER PARTNERS, LLC

Chet Lloyd
Project Executive

WS:hs

attachment

cc: Dave McNeal, USEPA Air, Pesticides and Toxics Management
all via email:
Art Diem, USEPA Clean Air Markets Division
Errin Pichard, FDEP Air Resource Management
Lee Hoefert, FDEP Southeast District
*Tim Gray, FDEP Southeast District*
Tom Cascio, FDEP Bureau of Air Regulation
Mike Halpin, FDEP Siting Coordination Office
K. M. Davis, FPL ACG/GO
E.N. Scoville II, FPL Director Construction
Sheila M. Wilkinson, FPL Designated Rep
Laxmana Tallam, PBC Health Department
Michael Helmke, PBC Health Department
Jim Stormer, PBC Health Department
Tom Tittle, PBC Health Department
Tom Young, FPL Construction Project General Manager
Jan Kirwan, FPL Environmental Specialist
Carmine Priore, FPL Plant General Manager
Chet Lloyd, WCPP Project Executive
John Tidwell, WCPP Senior Project Manager
Greg Hines, WCPP Site Environmental Manager
Terry Apple, WCPP Project Manager/ Project File
William Stevenson, WCPP Environmental Specialist

# EMISSIONS TEST PROTOCOL

**FOR**
**SIX MITSUBISHI 501G**
**COMBUSTION GAS TURBINES**
**(UNITS 1A, 1B, 1C, 2A, 2B, AND 2C)**

**PREPARED FOR**
**BLACK AND VEATCH**
**AND**
**FLORIDA POWER AND LIGHT**

**AT THE**
**WEST COUNTY**
**ENERGY CENTER**
**LOXAHATCHEE, FLORIDA**

**Florida Department of**
**Environmental Protection**
**Permit No. PSD-FL-354**

**November 10, 2009**

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**November 10, 2009**

Prepared By:

Jake Fahlenkamp, QSTI, Director of Quality Assurance

rev – 0b

## Table of Contents

# 1.0 INTRODUCTION

## 1.1 General Facility Description

Florida Power & Light (FPL) owns and operates the West County Energy Center (West County) located at 20505 State Road 80 in Loxahatchee, Florida. West County is a nominal 2,500 megawatt (MW) greenfield power plant and consists of two combined cycle units (Unit 1 and 2). Each combined cycle unit consists of: three nominal 250 MW Mitsubishi Model 501G combustion turbine-electrical generator (CTGs) sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSGs) with selective catalytic reduction (SCR) reactors; one nominal 428 million British thermal units per hour (MMBtu/hour) based on low heat value (LHV) natural gas-fired duct burner (DB) located within each of the three HRSG's; and a common nominal 500 MW steam turbine-electrical generator (STG). The total nominal generating capacity of each of the "3 on 1" combined cycle unit is approximately 1,250 MW.

Each CTG has a nominal heat input rate of 2,333 MMBtu/hr when firing natural gas and 2,117 MMBtu/hr when firing distillate fuel oil (based on a compressor inlet air temperature of 59 degrees Fahrenheit (°F), the lower heating value (LHV) of each fuel, and 100 percent load), includes an automated gas turbine control system, and has dual-fuel capability of firing natural gas as the primary fuel or ultra low sulfur distillate (ULSD) fuel oil as a restricted alternate fuel. Each HRSG recovers exhaust, heat energy from each of the CTGs. Each Unit delivers steam to each STG. The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of carbon monoxide (CO), particulate matter (PM), sulfuric acid mist ($H_2SO_4$), sulfur dioxide ($SO_2$) and volatile organic compounds (VOCs). Dry Low-NOx (DLN) combustors for gas firing and water injection for oil firing reduce nitrogen oxides (NOx) emissions. A selective catalyst reduction (SCR) system further reduces NOx emissions.

The 501G stacks are circular and measure 21.95 feet (ft) (263.38 inches) in diameter at the test ports which are approximately 138 ft above grade level with an exit elevation of approximately 150 ft above grade level. The test ports are located approximately 44.31 ft (531.75 inches) downstream and approximately 12 ft (144 inches) upstream from the nearest disturbances.

## 1.2 Reason for Testing

West County is a newly constructed plant subject to the regulatory requirements of the Florida Department of Environmental Protection (FDEP) [FDEP Permit No. PSD-FL-354, DEP File No. 0990646-001-AC, Appendix F] and the United States Environmental Protection Agency (EPA) [40 Code of Federal Regulations (CFR) Part 60, Subpart GG and Subpart KKKK] for initial compliance air emissions testing. As such, testing will include monitoring for NOx, CO, total hydrocarbons/volatile organic compounds (THC/VOC), ammonia slip ($NH_3$), fuel based total sulfur content (S), opacity, carbon dioxide ($CO_2$), and oxygen ($O_2$); on all units following the guidelines of 40 Code of Federal Regulations (CFR) Part 60. Each of these parameters will be monitored under one test condition, while the units are operating firing fuel oil.

This Protocol has been prepared and will be submitted to the FDEP prior to the first scheduled test date.

## 2.0 SUMMARY

### 2.1 Owner Information

| | |
|---|---|
| **Company:** | Florida Power & Light |
| **Contact:** | Danny Potter |
| **Mailing Address:** | 20505 State Road 80<br>Loxahatchee, Florida 33470 |
| **Office:** | (561) 904-4910 |
| **Cell:** | (561) 358-0079 |
| **Email:** | Danny.Potter@fpl.com |

### 2.2 EPC Contractor Information

| | |
|---|---|
| **Company:** | Black and Veatch Energy |
| **Contact:** | William Stevenson, Air Quality Control |
| **Mailing address:** | 11401 Lamar Avenue<br>Overland Park, Kansas 66211 |
| **Telephone:** | (913) 458-8549 |
| **Fax:** | (913) 458-2934 |
| **Email:** | StevensonWP@bv.com |

### 2.3 Test Contractor Information

| | |
|---|---|
| **Company:** | Air Hygiene International, Inc. |
| **Contact:** | Jake Fahlenkamp, Director of Quality Assurance |
| **Mailing Address:** | 5634 South 122nd East Avenue, Suite F<br>Tulsa, Oklahoma 74146 |
| **Office:** | (918) 307-8865 |
| **Cell:** | (918) 407-5166 |
| **Fax:** | (918) 307-9131 |
| **E-mail:** | jake@airhygiene.com |
| **Website:** | www.airhygiene.com |

### 2.4 Expected Test Start Date

Test dates are yet to be determined. Further notification will be provided by Black and Veatch (BV) Energy and/or FPL as a testing schedule is determined.

### 2.5 Testing Schedule

The following schedule indicates specific activities required to be done each day; however, the schedule is flexible and can be extended as necessary if there are operational or testing delays. If there are no operational delays, this schedule can be completed as detailed by the testing crew. The details below describe the activities to be conducted.

| Pre-test Activities | Due Date |
|---|---|
| 1. Receive site safety training | day of arrival for setup |
| 2. Conduct site inspection and pre-test meeting | per BV and/or Air Hygiene |
| 3. Prepare draft electronic test protocol | prior to start of project |

| On-Site Pre-testing Schedule | Time |
|---|---|
| Day 0 – Pre-test, initial site mobilization and setup | |
| • Arrive at site and attend safety training class | 08:00 – 09:00 |
| • Setup on Unit 1A | 09:00 – 11:00 |
| • Conduct preliminary testing of equipment | 11:00 – 13:00 |

| Compliance Testing | Time |
|---|---|
| Day 1 – Compliance Testing, Unit 1A, firing fuel oil | |
| • Daily setup and calibrations | 06:00 – 07:00 |
| • Conduct stratification testing and preliminary flow traverse<br>• Stratification testing for NOx and $O_2$<br>• Flow traverse for cyclonic flow profile, stack velocity, and stack temperature | 07:00 – 08:00 |
| • Conduct Testing for NOx, CO, THC/VOC, opacity, $CO_2$, and $O_2$<br>• NOx, CO, THC/VOC, opacity, $CO_2$, and $O_2$ testing (3, 1- hour test runs) | 08:00 – 13:00 |
| • Conduct Testing for $NH_3$ Slip<br>• $NH_3$ testing (3, 1-hour test runs)<br>• CO, $CO_2$, and $O_2$ will be monitored for molecular weight determinations | 08:00 – 13:00 |
| • Collect fuel oil sample for component analysis and total S | 08:00 – 13:00 |
| • Tear down from Unit 1A and setup on Unit 1B | 13:00 – 17:00 |

Additional days will follow the same timeline of Day 1 for units 1B, 1C, 2A, 2B, and 2C or test order determined by FPL and/or BV. Each unit will require one day of testing.

| Activities after Testing | Sequential Days |
|---|---|
| • Demobilization of Testing Crew | Day 1 |
| • Preparation of draft hard copy test report | Days 2 – 9 |
| • Submit for review to BV | Day 10 |
| • Review and comment on draft by BV | Days 11 – 14 |
| • Incorporate BV comments into draft copy | Days 15 – 19 |
| • Submit for review to FPL | Day 20 |
| • Review and comment on draft by FPL | Days 21 – 24 |
| • Incorporate FPL comments into draft copy | Days 25 – 29 |
| • Final reports delivered to FPL | Day 30 |

## 2.6 Hardcopy Compliance Report Content

The hard-copy compliance reports will be submitted to BV within 30 days of completion of testing and meet the requirements of the FDEP and the United States Environmental Protection Agency (EPA) for stack emissions testing. The reports will include discussion of the following:

- Introduction
- Plant and Sampling Location Description
- Summary and Discussion of Test Results Relative to Acceptance Criteria

- Sampling and Analytical Procedures
- QA/QC Activities
- Test Results and Related Calculations
- Sampling Log and Chain-of-Custody Records
- Audit Data Sheets

## 2.7 Equipment and Procedures

Reference methods (RM) and parameters to satisfy 40 CFR Part 51, 60, and 63 will include:

40 CFR Part 60, EPA RM 1 for sample location
40 CFR Part 60, EPA RM 2 for stack gas velocity
40 CFR Part 60, EPA RM 3a for $O_2$ and $CO_2$
40 CFR Part 60, EPA Method 4 for stack gas moisture content
40 CFR Part 60, EPA RM 7e for NOx
40 CFR Part 60, EPA RM 9 for opacity
40 CFR Part 60, EPA RM 10 for CO
40 CFR Part 60, EPA RM 18 for methane/ethane analysis, as required
40 CFR Part 60, EPA RM 19 for F-Factor determination of stack exhaust flow
40 CFR Part 60, EPA RM 25a for VOC
40 CFR Part 63, EPA Conditional Test Method (CTM) – 027 for $NH_3$ slip
EPA Report #600/4-79-020 Method 350.3 for $NH_3$ analysis
American Society of Testing Materials (ASTM) D420 for heat of combustion of liquid fuel (LF)
ASTM D5002 for American Petroleum Institute (API) gravity, density, and specific gravity of LF
ASTM D5453-00 for sulfur content of LF

## 2.8 Proposed Variations

- The $NO_2$ to NO converter check will be verified using the Emission Measurement Center's ALT-013 acceptable alternative procedure to section 8.2.4 of EPA Method 7e in Appendix A of 40 CFR Part 60 utilizing a $NO_2$ concentration around 50 parts per million.
- In lieu of borosilicate glass nozzles and probe liners, CTM-027 will utilize stainless steel and inconel to prevent breakage, particularly during port changes.
- RM 19 stoichiometrically calculated stack exhaust flows will be used to convert all gaseous, $NH_3$ concentrations to emission rates.
- If measured total hydrocarbon (THC) emission rates are below the required volatile organic compound (VOC) limits, all THCs will be assumed as VOCs and RM 18 analysis for methane and ethane will not be conducted.

## 2.9 Compliance Sampling Strategy

Testing will be performed on each CTG, at one load condition, while the units are combusting fuel oil. The emission compliance tests will follow the requirements of 40 CFR Part 51, 60, 63, and the FDEP permit. The tests for NOx, CO, THC/VOC, opacity, $NH_3$, $CO_2$, and $O_2$ will include at least three runs, approximately 60-minutes in duration at each load.

During each test run the following parameters will be recorded, based on availability, by the system operators from the system PLC and/or DAHS: water injection (gal/min), load (megawatts), heat input (MMBtu/hr), fuel flow (scfh), combustor inlet / compressor discharge pressure (psig), ambient temperature ($^{o}$F), ambient pressure (in. Hg), and ambient relative humidity (%).

### Gas Testing – EPA RM 3a, 7e, 10, 19, and 25a

A stratification test will be performed prior to air permit testing to determine the proper sample location(s). The air permit emissions test will include three test runs with analysis for NOx, CO, VOC, $CO_2$, and $O_2$ on the CTGs at each load. EPA RM 19 will be used to determine exhaust flow and calculate emission rates in pounds per million British thermal units (lb/MMBtu), lb/hr, and tons per year (tpy) at each load.

### Opacity Observations – EPA RM 9

Visual observations for opacity from each CTG at each load and from the AB will be determined using EPA RM 9. This method determines the level of any visible emissions that occur during the observation period. It requires that the opacity of emission be determined by a trained and certified individual. Three 60-minute runs will be observed from the proper location(s) on the CTG exhaust stack. The opacity level will be recorded every 15 seconds.

### Ammonia Slip Testing and Analysis – CTM 027

Ammonia slip testing will be conducted on each CTG at each load. Each test run will be approximately 60 minutes. An S-type pitot tube will be used to measure cyclonic flow and velocity pressure in accordance with EPA RM 2. This data will be correlated with meter coefficients, temperatures, barometric pressure, and exhaust gas moisture (EPA RM 4) to determine the exhaust gas dry flow rate. $NH_3$ samples will be collected following CTM 027 with an isokinetic sampling train utilizing a stainless steel nozzle and inconel probe liner. A scale will be used to measure net weight gain from each impinger to determine moisture gain.

The exit of the filter holder is connected to a series of four full size impingers. The first two impingers (Greensburg Smith) each contain 100 mL of 0.1 N $H_2SO_4$ which absorbs the ammonia when the sample is drawn through. The third impinger (Modified) is empty. The fourth contains a tared quantity of silica gel. The impingers are maintained at a temperature below 68$^{o}$F for the duration of each test.

Procedures for selecting sampling locations and for operation of the apparatus are derived from CTM 027 and associated EPA RMs 1 though 4. The sampling apparatus is leak-checked before and after each test run. Sampling is performed at an isokinetic rate greater than 90 percent and less than 110 percent.

The first impinger catch is measured, its weight recorded and the catch transferred to container No. 1. The second and third impinger catches are measured, their weights recorded and the catches transferred to container No. 2. The weight gain is added to the silica gel weight gain of the forth impinger to determine the stack gas moisture content. The connective glassware from the filter to the first impinger is rinsed with de-ionized water into container No. 1. The connective glassware from the back of impinger 1 to the front of impinger 4 is rinsed with deionized water into container No. 2.

Container contents are poured into a graduated cylinder and their volume recorded. After recording the volume the samples are returned to their respective containers, sealed, shaken and labeled, and the liquid level is marked. The samples are then refrigerated at approximately 39°F and allowed to slowly warm to laboratory room temperature before analysis.

$NH_3$ analysis is conducted using EPA Report #600/4-79-020 Method 350.3 on site by AHI. The ammonia is determined potentiometrically using an ion selective ammonia electrode and a pH meter having an expanded millivolt scale or a specific ion meter. The ammonia electrode uses a hydrophobic gas-permeable membrane to separate the sample solution from an ammonium chloride internal solution. Ammonia in the sample diffuses through the membrane and alters the pH of the internal solution, which is sensed by a pH electrode. The constant level of chloride in the internal solution is sensed by a chloride selective ion electrode which acts as the reference electrode.

A series of standard solutions covering the concentration range of the samples by diluting either the stock or standard solutions of ammonium chloride are prepared. The electrometer is calibrated by placing 100 mL of each standard solution in clean 150 mL beakers. The electrode is then immersed into standard of lowest concentration and 1 mL of 10N sodium hydroxide (NaOH) solution is added while mixing. The electrode is kept in the solution until a stable reading is obtained. This procedure is repeated with the remaining standards, going from lowest to highest concentration. The samples are then analyzed at room temperature following the same procedure as measuring the standards.

# APPENDIX A
# QA/QC PROGRAM

# TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after each testing project. The following paragraphs detail the quality control techniques, which are rigorously followed during testing projects.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range of the predicted values.

After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data just collected. The criteria on acceptable data is that the instrument drift shall be no more than 3 percent of the full-scale response. Quality assurance worksheets are prepared to document the multipoint calibration checks and zero to span checks performed during the tests (**See Appendix D**).

The sampling systems are leak checked by demonstrating that a vacuum greater than 10 in Hg could be held for at least 1 minute with a decline of less than 1 in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. These checks are performed to ensure that ambient air has not diluted the sample. Any leakage detected prior to the tests would be repaired and another leak check conducted before testing commenced.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the calibration gases introduced via two paths. The first path is directly into the analyzer and the second path via the sample system at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criteria for acceptance is agreement within 5% of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± 1% accuracy for all gases. EPA Protocol No. 1 gases will be used where applicable to assign concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials.

**AIR HYGIENE** maintains a large variety of calibration gases to allow the flexibility to accurately test emissions over a wide range of concentrations.

# APPENDIX B
# TEST EQUIPMENT CONFIGURATION AND DESCRIPTION

## INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures to be used conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1, 2, 3a, 4, 7e, 10, 18, 19, 25a; 40 CFR Part 63; and CTM-027.

Figure 1 depicts the sample system that will be used for the NOx, CO, THC, $CO_2$, and $O_2$ tests. A stainless steel probe will be inserted into the sample ports of the stack to extract gas measurements from the emission stream at multiple points or a single point determined after conducting an initial stratification test. The gas sample will be continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample and through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample will be partitioned to the NOx, CO, $CO_2$, and $O_2$ analyzers through rotameters that control the flow rate of the sample. Exhaust samples will be routed to the THC analyzer prior to gas conditioning.

The schematic (Figure 1) shows that the sample system will also be equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments will be housed in an air-conditioned, trailer-mounted mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor according to EPA Protocol No. 1.

This general schematic also illustrates the analyzers to be used for the tests (i.e., NOx, CO, and $O_2$). All data from the Reference Method continuous monitoring instruments are recorded on a Logic Beach Hyperlogger. The Hyperlogger retrieves calibrated emissions data from each instrument every second. An average value is recorded every 30 seconds.

The stack gas analysis for $O_2$ and $CO_2$ concentrations will be performed in accordance with procedures set forth in EPA Method 3a. The $O_2$ analyzer uses a paramagnetic cell detector and the $CO_2$ analyzer uses a continuous nondispersive infrared analyzer.

EPA Method 7e will be used to determine concentrations of NOx. A chemiluminescence analyzer will be used to determine the nitrogen oxides concentration in the gas stream. A $NO_2$ in nitrogen certified gas cylinder will be used to verify at least a 90 percent $NO_2$ conversion on the day of the test.

CO emission concentrations will be quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer will be used for this purpose.

THC emission concentrations will be quantified in accordance with procedures set forth in EPA Method 25a. A continuous flame ionization (FID) analyzer will be used for this purpose. All THC results will be assumed as VOCs. If results are greater than the permit limits a Tedlar bag sample will be taken and analyzed according to Method 18 for methane and ethane content. These results will then be subtracted from the THC concentrations to determine the VOC concentrations.

Figure 2 represents the sample system used for the $NH_3$ tests. For $NH_3$ a heated stainless steel probe sheath with an inconel liner will be inserted into a single sample point of the stack to extract gas measurements from the emission stream through a filter and glass impinger train in a constant flow rate fashion. Flow rates will be monitored with rotameters and total sample volumes will be measured with dry gas meters.

E:\SHARED\DRAWINGS\EMISSIONS TESTING LAB.PPT 04/18/08 DRAWING:08-001 TKG



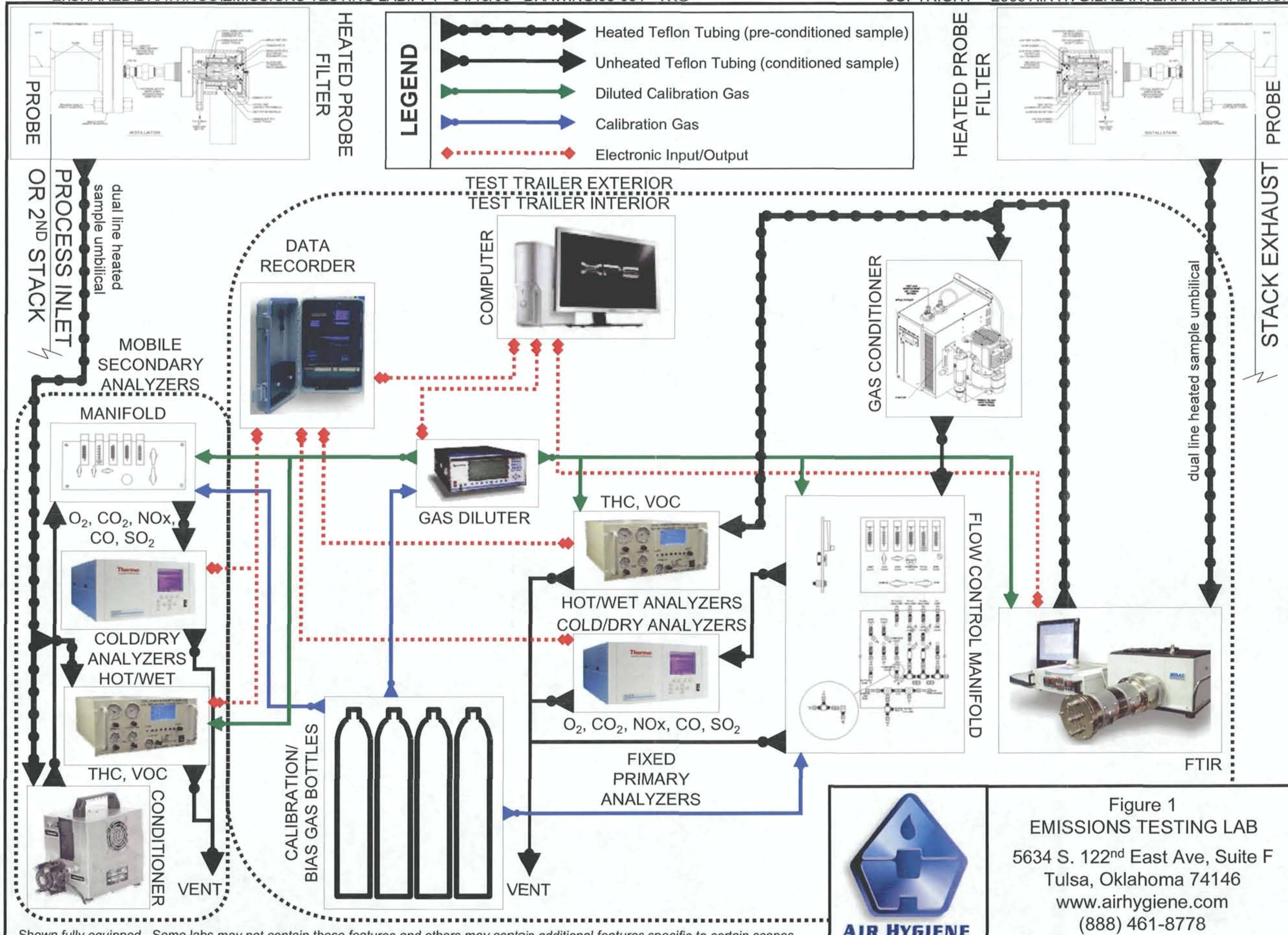


Figure 1
EMISSIONS TESTING LAB

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(888) 461-8778

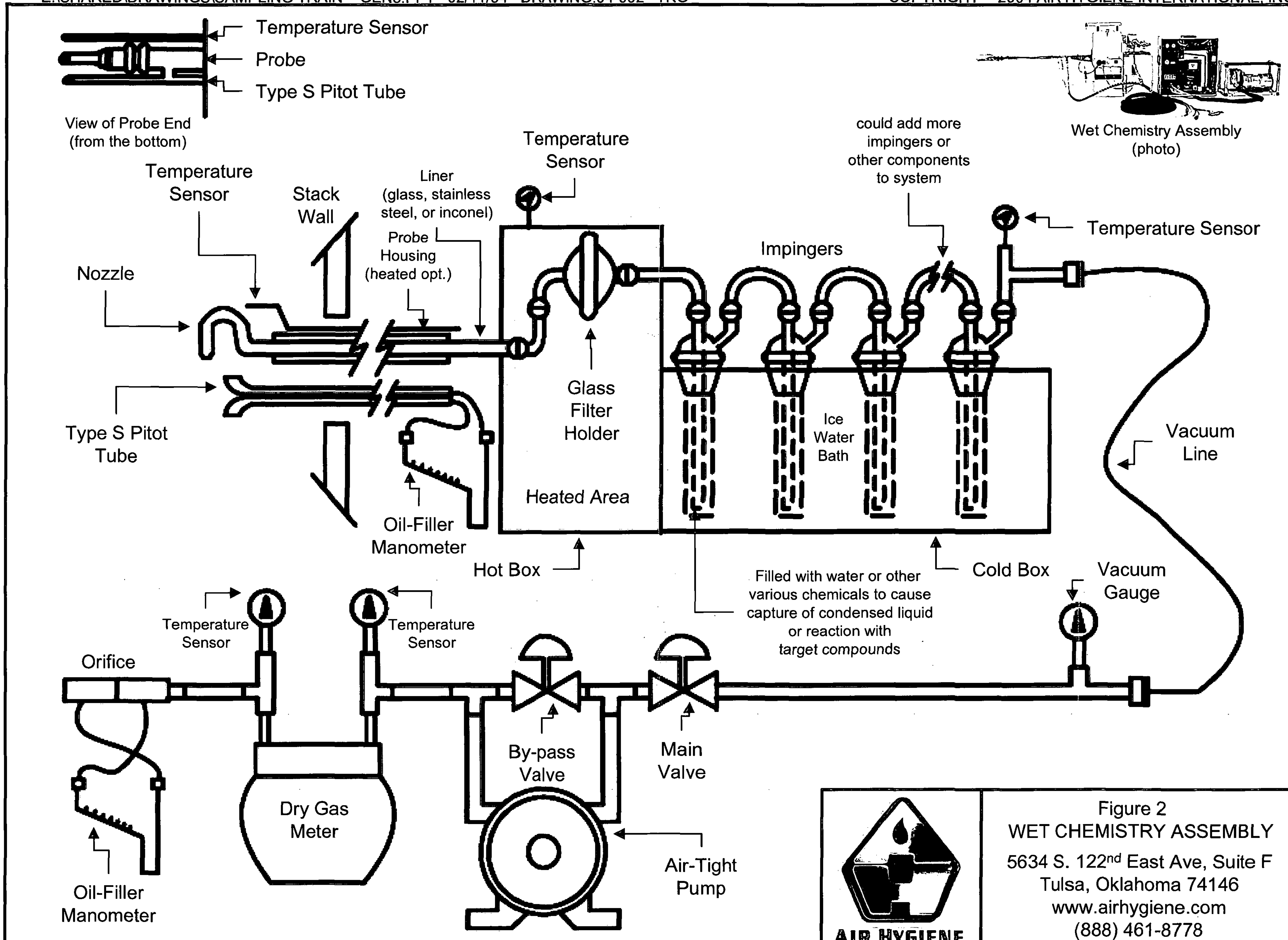


Figure 2
WET CHEMISTRY ASSEMBLY

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## TABLE #1: TESTING MATRIX

| Parameter | Source | Fuel | Load | No. Runs and Duration |
|---|---|---|---|---|
| NOx | CTG | Oil | 100% | 1 Strat Test (30 minutes) |
| | CTG | Oil | 100% | 3, 60 minute test runs |
| $O_2$ | CTG | Oil | 100% | 1 Strat Test (30 minutes) |
| | CTG | Oil | 100% | 3, 60 minute test runs |
| $CO_2$ | CTG | Oil | 100% | during $NH_3$ |
| CO | CTG | Oil | 100% | 3, 60 minute test runs |
| VOC | CTG | Oil | 100% | 3, 60 minute test runs |
| $NH_3$ | CTG | Oil | 100% | 3, 60 minute test runs |
| Opacity | CTG | Oil | 100% | 3, 60 minute test runs |
| Fuel Analysis | CTG | Oil | 100% | 3, 60 minute test runs |

## TABLE #2: ANALYTICAL INSTRUMENTATION

| Parameter | Model and Manufacturer | Max. Ranges | Sensitivity | Detection Principle |
|---|---|---|---|---|
| NOx | API 200AH or equivalent (1) | User may select up to 5,000 ppm | 0.1 ppm | Thermal reduction of $NO_2$ to NO Chemilumines-cence of reaction of NO with $O_3$. Detection by PMT. Inherently linear for listed ranges. |
| CO | API 300 or equivalent | User may select up to 3,000 ppm | 0.1 ppm | Infrared absorption, gas filter correlation detector, microprocessor based linearization. |
| $CO_2$ | FUJI 3300 or equivalent | 0-20% | 0.1% | Nondispersive infrared |
| THC | THERMO 51 or equivalent | User may select up to 10,000 ppm | 0.1 ppm | Flame Ionization Detector |
| $O_2$ | CAI 200 or equivalent | 0-25% | 0.1% | Paramagnetic cell, inherently linear. |

## TABLE #3: ANALYTICAL INSTRUMENTATION TESTING CONFIGURATION

| Parameter | Sample Methodology | Example Range | Sensitivity | Calibration Gases (based on example range) |
|---|---|---|---|---|
| NOx | 7e | 0-10 ppm | 0.1 ppm | Zero = 0 ppm nitrogen<br>Mid = 4-6 ppm<br>High = 10 ppm |
| CO | 10 | 0-50 ppm | 0.1 ppm | Zero = 0 ppm nitrogen<br>Mid = 20-30 ppm<br>High = 50 ppm |
| $CO_2$ | 3a | 0-20% | 0.1% | Zero = 0 ppm nitrogen<br>Mid = 8-12%<br>High = 20% |
| THC | 25a | 0-10 ppm | 0.1 ppm | Zero = 0 ppm nitrogen<br>Low = 2.5-3.5 ppm<br>Mid = 4.5-5.5 ppm<br>High = 8-9 ppm |
| $O_2$ | 3a | 0-21% | 0.1% | Zero = 0 ppm nitrogen<br>Mid = 8.4-12.6%<br>High = 21% |

## TABLE #4: PERMIT LIMITS

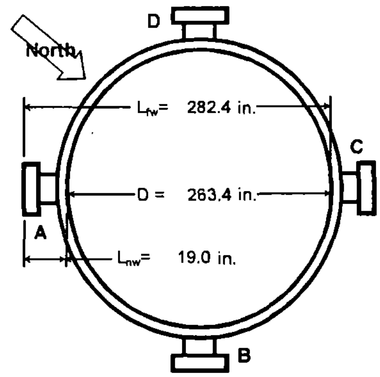
| Parameter | Source | Fuel | Limit |
|---|---|---|---|
| NOx | CTG | Oil | 8.0 ppmvd@15%$O_2$ / 82.4 lb/hr |
| CO | CTG | Oil | 8.0 ppmvd@15%$O_2$ / 42.0 lb/hr |
| VOC | CTG | Oil | 6.0 ppmvd@15%$O_2$ / 19.6 lb/hr |
| $NH_3$ | CTG | Oil | 5.0 ppmvd@15%$O_2$ |
| Opacity | CTG | Oil | 10% |
| Fuel Analysis | CTG | Oil | 0.0015% sulfur |

# APPENDIX C
# STACK DRAWINGS

# METHOD 1 - ISOKINETIC TRAVERSE FOR A CIRCULAR SOURCE

| | | | |
|---|---|---|---|
| **Company** | Florida Power and Light | **Date** | 2009 |
| **Plant Name** | West County Energy Center | **Project #** | bv-10-westcounty.fl-comp#1 |
| **Equipment** | Mistubishi 501G | **# of Ports Available** | 4 |
| **Location** | Loxahatchee, Florida | **# of Ports Used** | 4 |

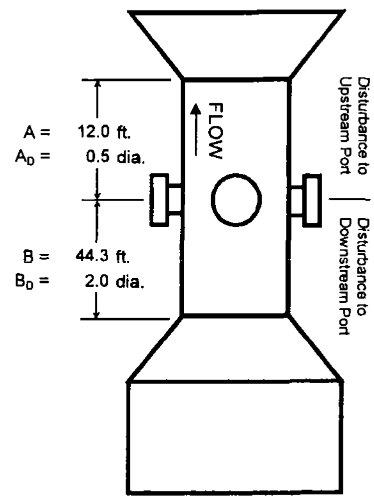
| **Circular Stack or Duct Diameter** | | | |
|---|---|---|---|
| **Distance to Far Wall of Stack** | ($L_{fw}$) | 282.38 | in. |
| **Distance to Near Wall of Stack** | ($L_{nw}$) | 19.00 | in. |
| **Diameter of Stack** | (D) | 263.38 | in. |
| **Area of Stack** | ($A_s$) | 378.35 | $ft^2$ |




| **Distance from Disturbances to Port** | | | |
|---|---|---|---|
| **Distance Upstream** | (A) | 144.00 | in. |
| **Diameters Upstream** | ($A_D$) | 0.55 | diameters |
| **Distance Downstream** | (B) | 531.75 | in. |
| **Diameters Downstream** | ($B_D$) | 2.02 | diameters |

| **Number of Traverse Points Required** | | | | | |
|---|---|---|---|---|---|
| **Diameters to Flow Disturbance** | | **Minimum Number of[1] Traverse Points** | | Minimum Number of Traverse Points Comp Stratification | |
| **Down ($B_D$) Stream** | **Up ($A_D$) Stream** | **Particulate Points** | Velocity Points | Criteria | Points |
| 2.00-4.99 | 0.50-1.24 | 24 | 16 | ● RM 7E 8.1.2 | 12 RM1 pts |
| 5.00-5.99 | 1.25-1.49 | 20 | 16 | ○ Alt 7E 8.1.2 | 3 points |
| 6.00-6.99 | 1.50-1.74 | 16 | 12 | | |
| 7.00-7.99 | 1.75-1.99 | 12 | 12 | | |
| >= 8.00 | >=2.00 | 8 or 12[2] | 8 or 12[2] | Minimum Number of Traverse Points RATA Stratification | |
| **Upstream Spec** | | 24 | 16 | | |
| **Downstream Spec** | | 24 | 16 | | |
| **Traverse Pts Required** | | 24 | 16 | Criteria | Points |
| | | | | ○ Part75/60 | 12 RM1 pts |
| | | | | ○ 75 abrv (a) | 3 points |
| | | | | ○ 75 abrv (b) | 6 points |

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches




| **Number of Traverse Points Used** | | | | |
|---|---|---|---|---|
| 4 | **Ports by** | 6 | **Pts / port** | **Isokinetic Traverse (Wet Chemistry** |
| 24 | **Pts Used** | 24 | **Required** | |

| **Traverse Point Locations** | | | |
|---|---|---|---|
| **Traverse Point Number** | **Percent of Stack Diameter** | **Distance from Inside Wall** | **Distance Including Reference Length** |
| | % | in. | in. |
| 1 | 2.1% | 5 4/8 | 24 4/8 |
| 2 | 6.7% | 17 5/8 | 36 5/8 |
| 3 | 11.8% | 31 1/8 | 50 1/8 |
| 4 | 17.7% | 46 5/8 | 65 5/8 |
| 5 | 25.0% | 65 7/8 | 84 7/8 |
| 6 | 35.6% | 93 6/8 | 112 6/8 |
| 7 | | | |
| 8 | | | |
| 9 | | | |
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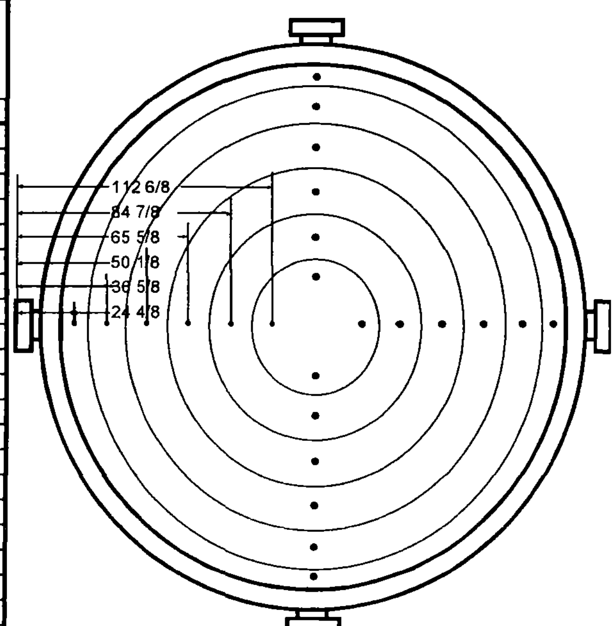
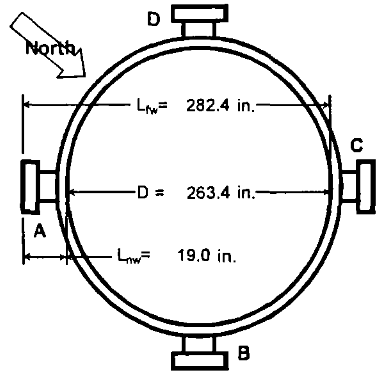
| 22 | | | |
| 23 | | | |
| 24 | | | |



## METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

| | | | |
|---|---|---|---|
| **Company** | Florida Power and Light | **Date** | 2009 |
| **Plant Name** | West County Energy Center | **Project #** | bv-10-westcounty.fl-comp#1 |
| **Equipment** | Mistubishi 501G | **# of Ports Available** | 4 |
| **Location** | Loxahatchee, Florida | **# of Ports Used** | 4 |

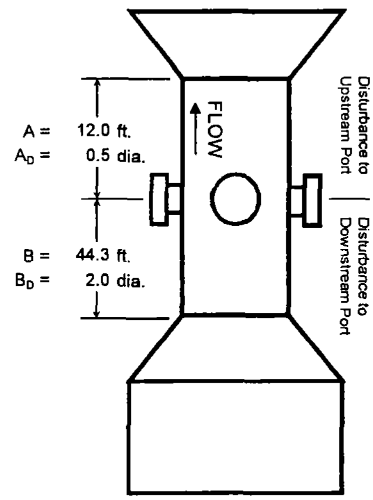
| Circular Stack or Duct Diameter | | | |
|---|---|---|---|
| **Distance to Far Wall of Stack** | ($L_{fw}$) | 282.38 | in. |
| **Distance to Near Wall of Stack** | ($L_{nw}$) | 19.00 | in. |
| **Diameter of Stack** | (D) | 263.38 | in. |
| **Area of Stack** | ($A_s$) | 378.35 | ft$^2$ |




| Distance from Disturbances to Port | | | |
|---|---|---|---|
| **Distance Upstream** | (A) | 144.00 | in. |
| **Diameters Upstream** | ($A_D$) | 0.55 | diameters |
| **Distance Downstream** | (B) | 531.75 | in. |
| **Diameters Downstream** | ($B_D$) | 2.02 | diameters |

| Number of Traverse Points Required | | | | | |
|---|---|---|---|---|---|
| Diameters to Flow Disturbance | | Minimum Number of[1] Traverse Points | | **Minimum Number of Traverse Points** | |
| Down ($B_D$) Stream | Up ($A_D$) Stream | Particulate Points | Velocity Points | **Comp Stratification Criteria** | **Points** |
| 2.00-4.99 | 0.50-1.24 | 24 | 16 | ● RM 7E 8.1.2 | 12 RM1 pts |
| 5.00-5.99 | 1.25-1.49 | 20 | 16 | ○ Alt 7E 8.1.2 | 3 points |
| 6.00-6.99 | 1.50-1.74 | 16 | 12 | 12 points | |
| 7.00-7.99 | 1.75-1.99 | 12 | 12 | | |
| >= 8.00 | >=2.00 | 8 or 12[2] | 8 or 12[2] | Minimum Number of Traverse Points | |
| Upstream Spec | | 24 | 16 | | |
| Downstream Spec | | 24 | 16 | RATA Stratification | |
| Traverse Pts Required | | 24 | 16 | Criteria | Points |
| | | | | ○ Part75/60 | 12 RM1 pts |
| | | | | ○ 75 abrv (a) | 3 points |
| | | | | ○ 75 abrv (b) | 6 points |

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches




| Number of Traverse Points Used | | | | |
|---|---|---|---|---|
| 4 | Ports by | 3 | Pts / port | Stratification Traverse |
| 12 | Pts Used | 12 | Required | (Compliance Test) |

| Traverse Point Number | Percent of Stack Diameter | Distance from Inside Wall | Distance Including Reference Length |
|---|---|---|---|
| | % | in. | in. |
| 1 | 4.4% | 11 5/8 | 30 5/8 |
| 2 | 14.6% | 38 4/8 | 57 4/8 |
| 3 | 29.6% | 78 | 97 |
| 4 | | | |
| 5 | | | |
| 6 | | | |
| 7 | | | |
| 8 | | | |
| 9 | | | |
| 10 | | | |
| 11 | | | |
| 12 | | | |
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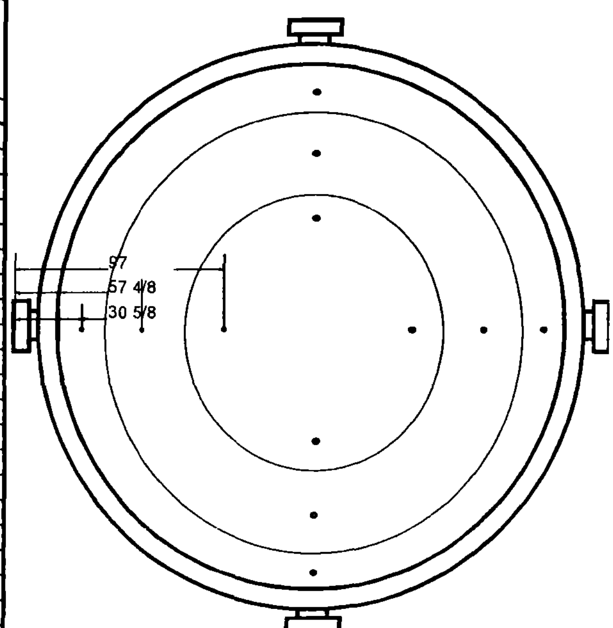
| 22 | | | |
| 23 | | | |
| 24 | | | |



# APPENDIX D
# EXAMPLE TEMPLATES AND CALCULATIONS

**SINGLE LOAD TEST - FIELD DATA SHEET**

**AIR HYGIENE**

| | | | |
|---|---|---|---|
| Company: | | | |
| Location: | | | |
| Date: | | | |
| Unit Make and Model: | | | |
| Unit Number: | | | |
| Serial Number: | | | |
| Data Recorded By: | | | |
| Tested With AHI Unit(s): | Truck(s): | Trailer(s): | |
| LDEQ Warmup/Cal Req: | On (Day/Time): | Cal (Day/Time): | |

| CYLINDER SERIAL NUMBERS | | $O_2$ | NOx | CO |
|---|---|---|---|---|
| | Low | | | |
| | Mid | | | |
| | High | | | |

| CYLINDER SERIAL NUMBERS | | THC | $CO_2$ | $SO_2$ |
|---|---|---|---|---|
| | Low | | | |
| | Mid | | | |
| | High | | | |

| RUN INFORMATION | Load | | |
|---|---|---|---|
| | _______% #1 | _______% #2 | _______% #3 |
| Time Start (hh:mm:ss) | | | |
| Time Stop (hh:mm:ss) | | | |
| Rated Power (MW or hp) | | | |
| Actual Power (MW or hp) | | | |
| Barometric Pressure (in. Hg) | | | |
| Ambient Temperature (°F) | | | |
| Relative Humidity (%) | | | |
| Fuel Flow (lb/min) | | | |
| Fuel Flow (SCF/hr)=(lb/min)*21.7 | | | |
| Specific Humidity (gr/lb) | | | |
| Spec. Hum. (lb $H_2O$/lb air)=(gr/lb)/7000 | | | |
| PCD (psi) | | | |
| PCD (mm Hg)=(psi+14.24)*51.71493 | | | |
| NOx Water Injection (gpm) | | | |

| $NO_2$ CONVERSION | |
|---|---|
| $NO_2$ Gas (ppm) | |
| NO Reading (ppm) | |
| NOx Reading (ppm) | |
| Cylinder Num | |

| REPORT INFORMATION | | |
|---|---|---|
| | INSTRUMENT | SERIAL # |
| $O_2$ | | |
| NOx | | |
| CO | | |
| THC | | |
| $CO_2$ | | |
| $SO_2$ | | |

| RESPONSE TIME | | |
|---|---|---|
| | TIME (hh:mm) | RESP (min) |
| 1st Gas Inject | | |
| 1st Inst. @ 95% | | |
| 2nd Inst. @ 95% | | |
| 3rd Inst. @ 95% | | |
| 2nd Gas Inject | | |
| 1st Inst. @ 95% | | |
| 2nd Inst. @ 95% | | |
| 3rd Inst. @ 95% | | |
| 3rd Gas Inject | | |
| 1st Inst. @ 95% | | |
| 2nd Inst. @ 95% | | |
| 3rd Inst. @ 95% | | |

| CALIBRATION | $O_2$ | | NOx | | CO | | THC | | $CO_2$ | | $SO_2$ | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Conc. | Actual | Conc. | Actual | Conc. | Actual | Conc. | Actual | Conc. | Actual | Conc. | Actual |
| Zero Gas | | | | | | | | | | | | |
| Low Gas | | | | | | | | | | | | |
| Mid Gas | | | | | | | | | | | | |
| High Gas | | | | | | | | | | | | |

| BIAS | $O_2$ | | NOx | | CO | | THC | | $CO_2$ | | $SO_2$ | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Zero | Mid | Zero | Mid | Zero | Mid | Zero | Mid | Zero | Mid | Zero | Mid |
| Initial Run #1 | | | | | | | | | | | | |
| Run #1 / Run #2 | | | | | | | | | | | | |
| Run #2 / Run #3 | | | | | | | | | | | | |
| Run #3 / Final | | | | | | | | | | | | |
| Bias Gas Actual Conc. | | ________ | | ________ | | ________ | | ________ | | ________ | | ________ |

| Source Information | |
|---|---|
| Company | |
| Plant Name | |
| Equipment | |
| Location | |

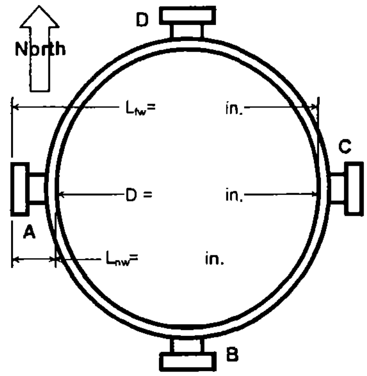
| Test Information | |
|---|---|
| Date | |
| Project # | |
| Unit Number | |
| Load | |
| Number of Ports Available | |
| Number of Ports Used | |

| Stack and Test Type | | | | |
|---|---|---|---|---|
| ○ | Isokinetic Traverse (Wet Chemistry Testing) | | | Circular Stack |
| ○ | Velocity Traverse (Flow and Flow RATA Test) | | | |
| ○ | Stratification Traverse (Compliance Test) | | ☐ RM 20 | |
| ◉ | **Stratification Traverse (RATA)** | ☐ Part 60 | ☑ Part 75 | |

**METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE**

| | | | |
|---|---|---|---|
| Company | | Date | |
| Plant Name | | Project # | |
| Equipment | | # of Ports Available | |
| Location | | # of Ports Used | |

| Circular Stack or Duct Diameter | | | |
|---|---|---|---|
| Distance to Far Wall of Stack | ($L_{fw}$) | | in. |
| Distance to Near Wall of Stack | ($L_{nw}$) | | in. |
| Diameter of Stack | (D) | | in. |
| Area of Stack | ($A_s$) | | $ft^2$ |

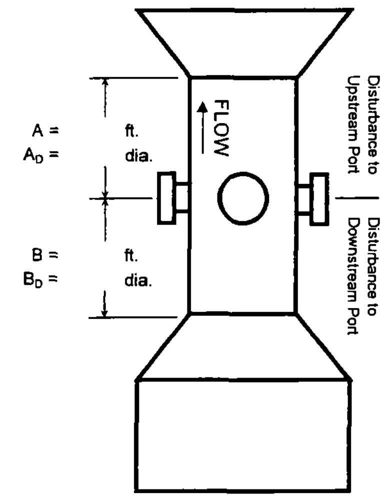



| Distance from Disturbances to Port | | | |
|---|---|---|---|
| Distance Upstream | (A) | | in. |
| Diameters Upstream | ($A_D$) | | diameters |
| Distance Downstream | (B) | | in. |
| Diameters Downstream | ($B_D$) | | diameters |

| Number of Traverse Points Required | | | | | |
|---|---|---|---|---|---|
| Diameters to Flow Disturbance | | Minimum Number of[1] Traverse Points | | Minimum Number of Traverse Points Comp Stratification | |
| Down ($B_D$) Stream | Up ($A_D$) Stream | Particulate Points | Velocity Points | Criteria | Points |
| 2.00-4.99 | 0.50-1.24 | 24 | 16 | ○ RM 7E 8.1.2 | 12 RM1 pts |
| 5.00-5.99 | 1.25-1.49 | 20 | 16 | ○ Alt 7E 8.1.2 | 3 points |
| 6.00-6.99 | 1.50-1.74 | 16 | 12 | | |
| 7.00-7.99 | 1.75-1.99 | 12 | 12 | | |
| >= 8.00 | >=2.00 | 8 or 12[2] | 8 or 12[2] | **Minimum Number of** | |
| Upstream Spec | | | | **Traverse Points** | |
| Downstream Spec | | | | **RATA Stratification** | |
| Traverse Pts Required | | | | **Criteria** | **Points** |
| | | | | ○ Part75/60 | 12 RM1 pts |
| | | | | ○ 75 abrv (a) | 3 points |
| | | | | ○ 75 abrv (b) | 6 points |

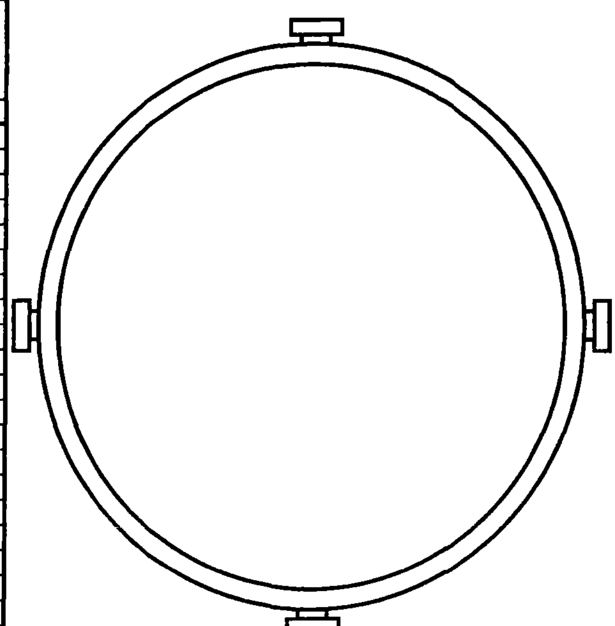
[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.

[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches




| Number of Traverse Points Used | | | | |
|---|---|---|---|---|
| | **Ports by** | | **Pts / port** | **Stratification Traverse** |
| | **Pts Used** | | **Required** | **(RATA)** |

| Traverse Point Locations | | | |
|---|---|---|---|
| **Traverse Point Number** | **Percent of Stack Diameter** | **Distance from *Inside Wall*** | **Distance Including Reference Length** |
| | % | in. | in. |
| **1** | | | |
| **2** | | | |
| **3** | | | |
| **4** | | | |
| **5** | | | |
| **6** | | | |
| **7** | | | |
| **8** | | | |
| **9** | | | |
| **10** | | | |
| **11** | | | |
| **12** | | | |
| **13** | | | |
| **14** | | | |
| **15** | | | |
| **16** | | | |
| **17** | | | |
| **18** | | | |
| **19** | | | |
| **20** | | | |
| **21** | | | |
| **22** | | | |
| **23** | | | |
| **24** | | | |



# STRATIFICATION TRAVERSE (RATA) RESULTS

| | | | |
|---|---|---|---|
| Company | | Date | |
| Plant Name | | Project # | |
| Equipment | | # of Ports Available | |
| Location | | # of Ports Used | |

| Stack Dimensions | | | | Traverse Data | | | |
|---|---|---|---|---|---|---|---|
| Diameter or Length of Stack | (D) | | in. | | Ports by | | Pts / port |
| Width of Stack | (W) | | in. | | Pts Used | | Required |
| Area of Stack | $(A_s)$ | | $ft^2$ | Run Start | | Run End | |

| Traverse Point | Time Per Point | Point Start Time | Point Stop Time (Reading) | Diluent 1 | Percent Difference | Pollutant 1 | Percent Difference |
|---|---|---|---|---|---|---|---|
| | min. | hh:mm:ss | hh:mm:ss | % | % | ppm | % |
| | | | | | | | |
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| | | | | | | | |
| Average | | | | | | | |

## RATA SAMPLE POINTS FOR CIRCULAR STACK

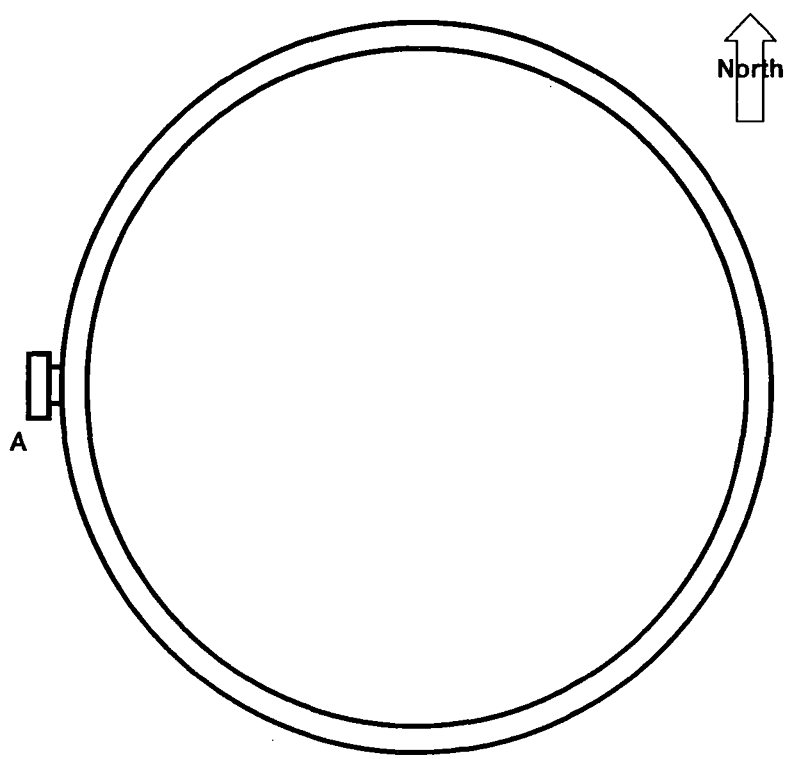
| | | | |
|---|---|---|---|
| Company | | Date | |
| Plant Name | | Project # | |
| Equipment | | # of Ports Available | |
| Location | | # of Ports Used | |

| Stack Dimensions | | | | Traverse Data | | | |
|---|---|---|---|---|---|---|---|
| Diameter or Length of Stack | (D) | | in. | | Ports by | | Pts / port |
| Width of Stack | (W) | | in. | | Pts Used | | Required |
| Area of Stack | $(A_s)$ | | $ft^2$ | Run Start | | Run End | |

| 40 CFR 75 Criteria | | | | | |
|---|---|---|---|---|---|
| Stratification Results | | Traverse Point Number | Percent of Stack Diameter | Distance from Inside Wall | Distance Including Reference Length |
| Maximum Percent Difference | No Test | | | | |
| Maximum Pollutant Conc. Diff. | No Test | | | | |
| Maximum Diluent Conc. Diff. | No Test | | | | |
| Stack Diameter | in. | | % | in. | in. |
| Stratification Conclusions | | 1 | | | |
| Maximum % Diff. | No Stratification Anticipated | 2 | | | |
| Maximum Conc. Diff. | No Stratification Anticipated | 3 | | | |
| Stack Diameter | D > 93.6 in. | | | | |

Use Short RM Measurement Line

Test Type
- ☐ Moisture, for MW
- ☐ Moisture, for wet-to-dry
- ☑ Gas
- ☐
- ☐ 6.5.6(b)(2) alt. points could apply



| DRIFT AND BIAS CHECK | | |
|---|---|---|
| Strat Test Pre and Post QA/QC Check | Diluent 1 | Pollutant 1 |
| Initial Zero | | |
| Final Zero | | |
| Avg. Zero | | |
| Initial UpScale | | |
| Final UpScale | | |
| Avg. UpScale | | |
| Sys Resp (Zero) | | |
| Sys Resp (Upscale) | | |
| Upscale Cal Gas | | |
| Initial Zero Bias | | |
| Final Zero Bias | | |
| Zero Drift | | |
| Initial Upscale Bias | | |
| Final Upscale Bias | | |
| Upscale Drift | | |
| Alternative Specification Abs Diff: Initial Zero | | |
| Final Zero | | |
| *Initial Upscale* | | |
| Final Upscale | | |
| Calibration Span | | |
| 3% of Range (drift) | | |
| 5% of Range (bias) | | |

| | | |
|---|---|---|
| Respone Time (min) | | |
| Sys. Response (min) | | |

INJECTIONS

Date/Time mm/dd/yy hh:mm:ss z s z s

x

**Client:**
**Location:**
**Date:**
**Project #:**

**Natural Gas - Fuel Analysis**

Standardized to 68 deg F and 14.696 psia - EPA Standards

| Gas Component | | Mole (%) | Molecular[1] Weight (lb/lb-mole) | Lbs Component per Lb-Mole of Gas | Wt. % of Component | Ideal Gross[1,3] Heating Value (Btu/ft$^3$) | Fuel Heat Value [HHV] (Btu/SCF) | Ideal Net[1,3] Heating Value (Btu/ft$^3$) | Fuel Heat Value [LHV] (Btu/SCF) |
|---|---|---|---|---|---|---|---|---|---|
| Methane | $CH_4$ | | | | | | | | |
| Ethane | $C_2H_6$ | | | | | | | | |
| Propane | $C_3H_8$ | | | | | | | | |
| iso-Butane | $iC_4H_{10}$ | | | | | | | | |
| n-Butane | $nC_4H_{10}$ | | | | | | | | |
| Iso-Pentane | $iC_5H_{12}$ | | | | | | | | |
| n-Pentane | $nC_5H_{12}$ | | | | | | | | |
| Hexanes | $C_6H_{14}$ | | | | | | | | |
| Heptanes | $C_7H_{16}$ | | | | | | | | |
| Octanes | $C_8H_{18}$ | | | | | | | | |
| Carbon Dioxide | $CO_2$ | | | | | | | | |
| Nitrogen | $N_2$ | | | | | | | | |
| Hydrogen Sulfide | $H_2S$ | | | | | | | | |
| Oxygen | $O_2$ | | | | | | | | |
| Helium | He | | | | | | | | |
| Hydrogen | $H_2$ | | | | | | | | |
| **Totals** | | | | | | dry | | dry | |
| | | | | | | wet[2,5] | | wet[2,5] | |

| Characteristics of Fuel Gas | | |
|---|---|---|
| Molecular Weight of gas = | | lb/lb-mole |
| Btu per lb. of gas[4] = | | gross (HHV) |
| Btu per lb. of gas[4] = | | net (LHV) |
| Density of fuel gas[2] = | | lb/cu. ft |
| Wt % VOC in fuel gas = | | % |
| Specific Gravity[1] = | | |

| Component | Wt% |
|---|---|
| carbon | |
| oxygen | |
| hydrogen | |
| nitrogen | |
| helium | |
| sulfur | |
| **Total** | |

**F-Factor (SCF dry exhaust per MMBtu [HHV]) =**
(Based on EPA RM-19) at 68 deg F and 14.696 psia

**F-Factor Calculation:**

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

GCV = Gross Btu per lb. of gas (HHV)

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

Density of natural gas based on specific gravity multiplied by density of air at 68 deg F and 14.696 psia.

**References:**

[1] ASTM D 3588
[2] Civil Engineering Reference Manual, 7th ed. - Michael R. Lindeburg
[3] Mark's Standard Handbook for Mechanical Engineers, 10th ed. - Eugene A. Avallone, Theodore Baumeister III
[4] Introduction to Fluid Mechanics, 3rd ed. - William S. Janna
[5] GPA Reference Bulletin 181-86, revised 1986, reprinted 1995

| | |
|---|---|
| Air Permit # : | |
| Plant Name or Location: | |
| Date: | |
| Project Number: | |
| Manufacturer & Equipment: | |
| Model: | |
| Serial Number: | |
| Unit Number: | |
| Test Load: | |
| Tester(s) / Test Unit(s): | |

| | | RUN | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | UNITS | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| Start Time | hh:mm:ss | | | | | | | | | | | | | | | | | | |
| End Time | hh:mm:ss | | | | | | | | | | | | | | | | | | |
| Bar. Pressure | in. Hg | | | | | | | | | | | | | | | | | | |
| Amb. Temp. | °F | | | | | | | | | | | | | | | | | | |
| Rel. Humidity | % | | | | | | | | | | | | | | | | | | |
| Spec. Humidity | lb water / lb air | | | | | | | | | | | | | | | | | | |
| Comb. Inlet Pres. | psig | | | | | | | | | | | | | | | | | | |
| NOx Water Inj. | gpm | | | | | | | | | | | | | | | | | | |
| Total Fuel Flow | SCFH | | | | | | | | | | | | | | | | | | |
| Heat Input | MMBtu/hr | | | | | | | | | | | | | | | | | | |
| Power Output | megawatts | | | | | | | | | | | | | | | | | | |
| Steam Rate | lb/hr | | | | | | | | | | | | | | | | | | |

**Client:**
**Location:**
**Date:**
**Project #:**

**Fuel Oil - Fuel Analysis**

| Characteristics of Fuel Gas | | |
|---|---|---|
| Molecular Weight of oil = | | lb/lb-mole |
| Btu per lb. of oil = | | gross (HHV) |
| Btu per lb. of oiil = | | net (LHV) |
| Density of fuel oil[2] = | | lb/cu. ft |
| Density of fuel oil[2] = | | lb/gal |
| Specific Gravity = | | @ 68 deg F |

Standardized to 68 deg F and 14.696 psia

| Component | Wt% |
|---|---|
| carbon | |
| oxygen | |
| hydrogen | |
| nitrogen | |
| helium | |
| sulfur | |
| **Total** | |

| Fuel Oil HHV Conv. | |
|---|---|
| HHV (Btu/lb) | |
| HHV (Btu/SCF) | |

| Fuel Oil LHV Conv. | |
|---|---|
| LHV (Btu/lb) | |
| LHV (Btu/SCF) | |

| **F-Factor (SCF dry exhaust per MMBtu [HHV]) =** |
|---|
| (Based on EPA RM-19) at 68 deg F and 14.696 psia |

**F-Factor Calculation:**

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

GCV = Gross Btu per lb. of gas (HHV)

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

Density of fuel oil based on lab analysis or specific gravity multiplied by density of water at 68 deg F and 14.696 psia.

**References:**


[1] ASTM D 3588

[2] Civil Engineering Reference Manual, 7th ed. - Michael R. Lindeburg

[3] Mark's Standard Handbook for Mechanical Engineers, 10th ed. - Eugene A. Avallone, Theodore Baumeister III

[4] Introduction to Fluid Mechanics, 3rd ed. - William S. Janna

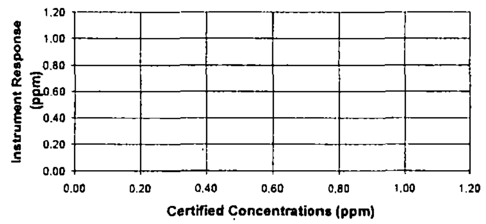
[5] GPA Reference Bulletin 181-86, revised 1986, reprinted 1995

**Calibration Date:**
**Client:**

NOx Span (ppm) =

| THERMO 42H (NOx Analyzer) | | | | |
|---|---|---|---|---|
| Certified Concentration (ppm) | Instrument Response (ppm) | Calibration Error (%) | Absolute Conc. (ppm) | Pass or Fail (±2%, ≤0.5ppm) |
| | | | | |
| | | | | |
| | | | | |
| Linearity = | | | | |

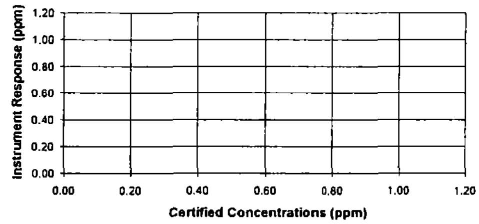
THERMO 42H (NOx Analyzer) Linearity Plot




CO Span (ppm) =

| API 300 (CO Analyzer) | | | | |
|---|---|---|---|---|
| Certified Concentration (ppm) | Instrument Response (ppm) | Calibration Error (%) | Absolute Conc. (ppm) | Pass or Fail (±2%, ≤0.5ppm) |
| | | | | |
| | | | | |
| | | | | |
| Linearity = | | | | |

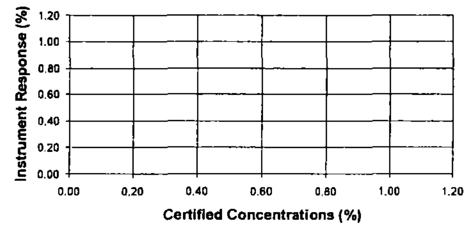
API 300 (CO Analyzer) Linearity Plot




O2 Span (%) =

| SERVOMEX 1400 ($O_2$ Analyzer) | | | | |
|---|---|---|---|---|
| Certified Concentration (ppm) | Instrument Response (ppm) | Calibration Error (%) | Absolute Conc. (ppm) | Pass or Fail (±2%, ≤0.5%) |
| | | | | |
| | | | | |
| | | | | |
| Linearity = | | | | |

SERVOMEX 1400 (O2 Analyzer) Linearity Plot

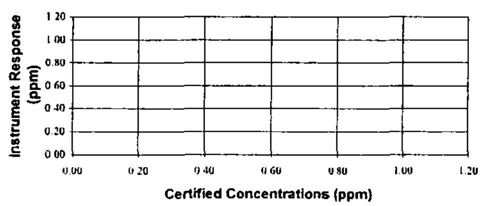



THC Range (ppm) =

| THERMO 51 (THC Analyzer) | | | | |
|---|---|---|---|---|
| Certified Concentration (ppm) | Instrument Response (ppm) | Calibration Error (%) | Estimated Point (ppm) | Pass or Fail (±2,5%)[1] |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| Linearity = | | | | |

[1]-zero/high based on 2% of span low/mid based on 5% of concentration

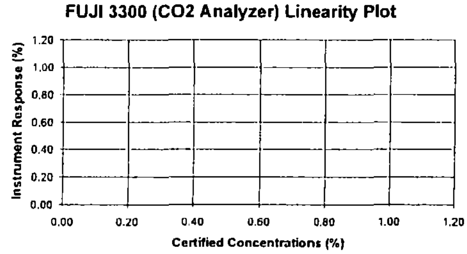
THERMO 51 (THC Analyzer) Linearity Plot




CO2 Span (%) =

| FUJI 3300 ($CO_2$ Analyzer) | | | | |
|---|---|---|---|---|
| Certified Concentration (ppm) | Instrument Response (ppm) | Calibration Error (%) | Absolute Conc. (ppm) | Pass or Fail (±2%, ≤0.5%) |
| | | | | |
| | | | | |
| | | | | |
| Linearity = | | | | |

FUJI 3300 (CO2 Analyzer) Linearity Plot



**NOx Converter Efficiency**

**Date:**

**Analyzer:**

RM 7E, (08-15-06), 8.2.4.1 Introduce a concentration of 40 to 60 ppmv $NO_2$ to the analyzer in direct calibration mode and record the NOx concentration displayed by the analyzer. ... Calculate the converter efficiency using Equation 7E-7 in Section 12.7. The specification for converter efficiency in Section 13.5 must be met. ... The $NO_2$ must be prepared according to the EPA Traceability Protocol and have an accuracy within 2.0 percent.

**Audit Gas:** $NO_2$ Concentration ($C_v$), ppmvd

**Converter Efficiency Calculations:**

Analyzer Reading, NO Channel, ppmvd

Analyzer Reading, NOx Channel, ppmvd

Analyzer Reading, $NO_2$ Channel ($C_{Dir(NO2)}$), ppmvd

Converter Efficiency, %

RM 7E, (08-15-06), 13.5 NO2 to NO Conversion Efficiency Test (as applicable). The NO2 to NO conversion efficiency, calculated according to Equation 7E-7 or Equation 7E-9, must be greater than or equal to 90 percent.

$$Eff_{NO2} = \left( \frac{C_{Dir}}{C_V} \right) \times 100$$

Eq. 7E-7 = $\frac{\text{ppmvd}}{\text{ppmvd}}$ x 100 =

| Date/Time | Elapsed Time | NOx | NO |
|---|---|---|---|
| mm/dd/yy hh:mm:ss | Seconds | ppmvd | ppmvd |

**Fuel Data**

| | | |
|---|---|---|
| Fuel $F_s$ factor | | SCF/MMBtu |
| Fuel Heating Value (HHV) | | Btu/SCF |

**Weather Data**

| | | |
|---|---|---|
| Barometric Pressure | | in. Hg |
| Relative Humidity | | % |
| Ambient Temperature | | °F |
| Specific Humidity | | lb $H_2O$ / lb air |

**Unit Data**

| | | |
|---|---|---|
| Unit Load | | megawatts |
| Heat Input | | lb/MMBtu |
| Steam Rate | | Steam lb/hr |
| Combustor Inlet Pres. | | psig |
| NOx Control Water Injection | | gpm |
| Est. Stack Moisture | | % |
| Stack Exhaust Flow (M2) | | SCFH |
| Stack Exhaust Flow (M19) | | SCFH |

Run - 1

| Date/Time (mm/dd/yy hh:mm:ss) | Elapsed Time (seconds) | $O_2$ (%) | NOx (ppmvd) | CO (ppmvd) |
|---|---|---|---|---|

**RAW AVERAGE**

| | | $O_2$ | NOx | CO |
|---|---|---|---|---|
| | **Serial Number:** | | | |
| | | **(%)** | **(ppmvd)** | **(ppmvd)** |
| | **Initial Zero** | | | |
| | **Final Zero** | | | |
| | **Avg. Zero** | | | |
| **Bias** | | | | |
| | **Initial UpScale** | | | |
| | **Final UpScale** | | | |
| | **Avg. UpScale** | | | |

**Upscale Cal Gas**

| EMISSIONS DATA | $O_2$ | NOx | CO |
|---|---|---|---|
| Corrected Raw Average (ppm/% dry basis) | | | |
| Corrected Raw Average (ppm/% wet basis) | | | |
| Concentration (ppm@ %$O_2$ ) | | | |
| Concentration (ppm@ %$O_2$ &ISO) | | | |
| Emission Rate (lb/hr) | | | |
| Emission Rate (tons/day) at 24 hr/day | | | |
| Emission Rate (tons/year) at 8760 hr/yr | | | |
| Emission Rate (lb/MMBtu) | | | |
| Emission Rate (g/hp*hr) | | | |

| DRIFT AND BIAS CHECK | | | |
|---|---|---|---|
| Run - 1 | O2 | NOx | CO |
| Raw Average | | | |
| Corrected Average | | | |
| Initial Zero | | | |
| Final Zero | | | |
| Avg. Zero | | | |
| Initial UpScale | | | |
| Final UpScale | | | |
| Avg. UpScale | | | |
| Sys Resp (Zero) | | | |
| Sys Resp (Upscale) | | | |
| Upscale Cal Gas | | | |
| Initial Zero Bias | | | |
| Final Zero Bias | | | |
| Zero Drift | | | |
| Initial Upscale Bias | | | |
| Final Upscale Bias | | | |
| Upscale Drift | | | |
| Alternative Specification Abs Diff: Initial Zero | | | |
| Final Zero | | | |
| Initial Upscale | | | |
| Final Upscale | | | |
| Calibration Span | | | |
| 3% of Range (drift) | | | |
| 5% of Range (bias) | | | |

| DRIFT AND BIAS CHECK | | | |
|---|---|---|---|
| Run - 2 | O2 | NOx | CO |
| Raw Average | | | |
| Corrected Average | | | |
| Initial Zero | | | |
| Final Zero | | | |
| Avg. Zero | | | |
| Initial UpScale | | | |
| Final UpScale | | | |
| Avg. UpScale | | | |
| Sys Resp (Zero) | | | |
| Sys Resp (Upscale) | | | |
| Upscale Cal Gas | | | |
| Initial Zero Bias | | | |
| Final Zero Bias | | | |
| Zero Drift | | | |
| Initial Upscale Bias | | | |
| Final Upscale Bias | | | |
| Upscale Drift | | | |
| Alternative Specification Abs Diff: Initial Zero | | | |
| Final Zero | | | |
| Initial Upscale | | | |
| Final Upscale | | | |
| Calibration Span | | | |
| 3% of Range (drift) | | | |
| 5% of Range (bias) | | | |

## TABLE A.2
## LOAD 1 DATA SUMMARY

| Parameter | Run - 1 | Run - 2 | Run - 3 | Average |
|---|---|---|---|---|
| Start Time (hh:mm:ss) | | | | |
| End Time (hh:mm:ss) | | | | |
| Run Duration (min) | | | | |
| Bar. Pressure (in. Hg) | | | | |
| Amb. Temp. (°F) | | | | |
| Rel. Humidity (%) | | | | |
| Spec. Humidity (lb water / lb air) | | | | |
| Turbine Fuel Flow (SCFH) | | | | |
| Stack Flow (RM19) (SCFH) | | | | |
| Power Output (megawatts) | | | | |
| NOx (ppmvd) | | | | |
| NOx (lb/hr) | | | | |
| NOx (lb/MMBtu) | | | | |
| NOx (g/hp*hr) | | | | |
| CO (ppmvd) | | | | |
| CO (lb/hr) | | | | |
| CO (lb/MMBtu) | | | | |
| CO (g/hp*hr) | | | | |
| $O_2$ (%) | | | | |

## TABLE A.3
## LOAD 2 DATA SUMMARY

| Parameter | Run - 4 | Run - 5 | Run - 6 | Average |
|---|---|---|---|---|
| Start Time (hh:mm:ss) | | | | |
| End Time (hh:mm:ss) | | | | |
| Run Duration (min) | | | | |
| Bar. Pressure (in. Hg) | | | | |
| Amb. Temp. (°F) | | | | |
| Rel. Humidity (%) | | | | |
| Spec. Humidity (lb water / lb air) | | | | |
| Turbine Fuel Flow (SCFH) | | | | |
| Stack Flow (RM19) (SCFH) | | | | |
| Power Output (megawatts) | | | | |
| NOx (ppmvd) | | | | |
| NOx (lb/hr) | | | | |
| NOx (lb/MMBtu) | | | | |
| NOx (g/hp*hr) | | | | |
| CO (ppmvd) | | | | |
| CO (lb/hr) | | | | |
| CO (lb/MMBtu) | | | | |
| CO (g/hp*hr) | | | | |
| $O_2$ (%) | | | | |

**EXAMPLE CALCULATIONS (FFACTOR)**

RM 19, (07-19-06), 2.0 Summary of Method, 2.1 Emission Rates. Oxygen ($O_2$) or carbon dioxide ($CO_2$) concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant co

RM 19, (07-19-06), 12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in lb/MMBtu. The pollutant concentration must be in lb/scf and the F factor must be in scf/MMBtu. If the pollutant concentration (C) is not in the appropriate units, use Table 19–1 in Section 17.0 to make the proper conversion. An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. The dry F factor ($F_d$) includes all components of combustion less water, the wet F factor ($F_w$) includes all components of combustion, and the carbon F factor ($F_c$) includes only carbon dioxide.

Mark's Std Hdbk, 10th ed.,pg 4-26
**High Heat Value Dry** ($HHV_{dry}$), calc for Methane (single component for the fuel gas)

$$HHV_{dry}(Btu/SCF) = \left[\left(\frac{M_{\%}}{100}\right) \times GCM\right] \qquad HHV_{dry} = \frac{\%}{100.00} \times \frac{Btu}{SCF} = \frac{Btu}{SCF}$$

Mark's Std Hdbk, 10th ed., pg 4-26
**Low Heat Value Dry** ($LHV_{dry}$), calc for Methane (single component for the fuel gas)

$$LHV_{dry}(Btu/SCF) = \left[\left(\frac{M_{\%}}{100}\right) \times NCM\right] \qquad LHV_{dry} = \frac{\%}{100.00} \times \frac{Btu}{SCF} = \frac{Btu}{SCF}$$

Civil Eng. Ref. Man.,7th Ed.,pg 14-9/GPA Ref. Bulletin 181-86, App. C
**High Heat Value Wet** ($HHV_{wet}$), calc for entire sample (all components of the fuel gas)

$$HHV_{wet}(Btu/SCF) = \frac{HHV_{dry}}{W/D.factor} \qquad HHV_{wet} = \frac{Btu/SCF}{} = Btu/SCF$$

Civil Eng. Ref. Man.,7th Ed.,pg 14-9/GPA Ref. Bulletin 181-86, App. C
**Low Heat Value Wet** ($LHV_{wet}$), calc for entire sample (all components of the fuel gas)

$$LHV_{wet}(Btu/SCF) = \frac{LHV_{dry}}{W/D.factor} \qquad LHV_{wet} = \frac{Btu/SCF}{} = Btu/SCF$$

**Lbs Component per Lb-Mol of Gas** (CM), calc for Methane (single component for the fuel gas)

$$CM(lb/lb-mol) = \left[\left(\frac{M_{\%}}{100}\right) \times MW\right] \qquad CM = \frac{\%}{100.00} \times \frac{lb}{lb\text{-}mol} = \_\_\_ \ lb/lb\text{-}mol$$

ASTM D 3588
**Fuel Molecular Weight** ($MW_{Fuel}$)

$$MW_{Fuel}(lb/lb \cdot mol) = \left[\sum(CM)\right]$$

$MW_{Fuel}$ = lb/lb-mol
\+ lb/lb-mol
\+ etc. = lb/lb-mol

Btu per Lb of Gas Gross (**GCV**)

$$GCV(Btu/lb) = \left[\frac{HHV_{dry} \times G}{MW_{Fuel}}\right]$$

$$GCV = \frac{Btu/SCF \ \times \ ft^3/lbmol}{lb/lb\text{-}mol} = Btu/lb$$

ASTM D 3588 (SG)
**Specific Gravity**

$$SG = \left[\frac{MW_{Fuel}}{MW_{AIR}}\right] \qquad SG = \frac{lb/lb\text{-}mol}{28.96\ lb/lb\text{-}mol} =$$

Btu per Lb of Gas Net (**NCV**)

$$NCV(Btu/lb) = \left[\frac{LHV_{dry} \times G}{MW_{Fuel}}\right]$$

$$NCV = \frac{Btu/SCF \ \times \ ft^3/lbmol}{lb/lb\text{-}mol} = Btu/lb$$

**Weight Percent** of Component ($C_{\%}$), methane

$$C_{\%}(\%) = \left[\left(\frac{CM}{MW_{Fuel}}\right) \times 100\right]$$

$$C_{\%} = \frac{lb/lb\text{-}mol}{lb/lb\text{-}mol} \times 100 = \%$$

RM 19, (07-19-06), **Weight Percent of Volatile Organic Compounds** ($VOC_{\%}$)

$$VOC_{\%}(\%) = \left[\sum_{C_3H_8}^{C_nH_n} M_{\%}\right] \qquad VOC_{\%} = \ \% + \ \% + \ \% + etc. = \ \%$$

RM 19, (07-19-06), 12.3.2 Determined **F Factors**. If the fuel burned is not listed in Table 19–2 or if the owner or operator chooses to determine an F factor rather than use the values in Table 19–2, use the procedure below: 12.3.2.1 Equations. Use the eq

RM 19, (07-19-6), 12.1 Nomenclature

$$F_d = \frac{K(K_{hd}\%H + K_c\%C + K_s\%S + K_n\%N - K_o\%O)}{GCV} \qquad \text{Eq. 19-13}$$

**K (scf/lb)/%**

| | |
|---|---|
| H | 3.64 |
| C | 1.53 |
| S | 0.57 |
| $N_2$ | 0.14 |
| $O_2$ | 0.46 |

$$F_d = \frac{10^6 Btu}{MMBtu} \times \left[\frac{3.64\ SCF}{lb \cdot \%} \times \ \% + \frac{1.53\ SCF}{lb \cdot \%} \times \ \% + \frac{0.57\ SCF}{lb \cdot \%} \times \ \% + \frac{0.14\ SCF}{lb \cdot \%} \times \ \% - \frac{0.46\ SCF}{lb \cdot \%} \times \ \%\right] \times \frac{lb}{Btu} = \frac{SCF}{MMBtu}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

**EXAMPLE CALCULATIONS (INFORMATION)**

**Specific Humidity ($RH_{sp}$)**

Note: RHsp (gr/lb) calculated using temperature, relative humidity, and barometric pressure with psychrometric chart, psychrometric calculator, or built in psychrometric algorithm.

$$RH_{sp}(lb/lb) = \left[\left(\frac{gr}{lb}\right) \times \frac{lb}{7000\,gr}\right]$$

$RH_{sp} = \frac{\quad gr}{lb} \times \frac{1\,lb}{7000\,gr} = \frac{lb\,H_2O}{lb\,Air}$

**Fuel Flow Conversion ($Q_f$)**

Note: Qf(lb/min) is a value uptained from the source operator.

$$Q_f = \left[Q_f \times G \times \left(\frac{1}{MW_{Fuel}}\right)\right]$$

$Q_f = \frac{\quad lb}{min} \times \frac{60\,min}{hr} \times \frac{\quad ft^3}{lb\text{-}mol} \times \frac{lb\text{-}mol}{lb} = \quad$ SCFH

**Combustor Inlet Pressure / Compressor Discharge Pressure (CIP / CDP)**
(corrected from gauge to atmospheric pres. and conv. to mm Hg.)

Note: CIP / CDP (psig) is a value obtained from the source operator.

$$CIP/CDP = \left[(psig + P) \times \frac{51.71493\,mmHg}{1psi}\right]$$

CIP / CDP = ( psig + ) x $\frac{51.71493\,mmHg}{1\,psia}$ = mmHg (abs)

**Heat Rate (MMBtu/hr)**

$$HR = \frac{HHV_{DRY} \times Q_f}{1{,}000{,}000}$$

Heat Rate = $\frac{\quad Btu}{SCF} \times \frac{\quad SCF}{hr} \times \frac{MMBtu}{10^6\,Btu} = \frac{\quad MMBtu}{hr}$

**Estimated Stack Gas Moisture Content ($B_{ws}$)**

$$B_{ws}(\%) = \frac{2 \times Q_f}{Q_s} \times 100$$

$B_{ws} = 2 \times \frac{\quad SCF}{hr} \times \frac{\quad hr}{SCF} \times 100 = \quad \%$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

**EXAMPLE CALCULATIONS (CALIBRATION)**

**Analyzer Calibration Error**

RM 7E, (08-15-06), 12.2 Analyzer Calibration Error. For non-dilution systems, use Equation 7E-1 to calculate the analyzer calibration error for the low-, mid-, and high-level calibration gases. (calc for analyzer mid gas, if applicable)

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100$$

Eq. 7E-1

ACE = $\frac{ppm - \quad ppm}{ppm} \times 100 = \quad \%$

**Calibration Error and Estimated Point, RM 25A, THC Analyzer**

RM 25A, (07-19-06), 8.4 Calibration Error Test. Immediately prior to the test series (within 2 hours of the start of the test), introduce zero gas and high-level calibration gas at the calibration valve assembly. Adjust the analyzer output to the appropriate levels, if necessary. Calculate the predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response. Then introduce low-level and mid-level calibration gases successively to the measurement system. ... These differences must be less than 5 percent of the respective calibration gas value. (calc for THC analyzer mid gas, if applicable)

$$E_p = \frac{C_{Dir(H)} - C_{Dir(Z)}}{C_{V(H)} - C_{V(Z)}} \times C_{Dir(M)} + C_{Dir(Z)}$$

Eq. of a line
y=mx+b

$E_p = \frac{ppm - \quad ppm}{ppm - \quad ppm} \times \quad ppm + \quad = \quad ppm$

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100$$

Eq. 7E-1

$ACE_{THC} = \frac{ppm - \quad ppm}{ppm} \times 100 = \quad \%$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

**EXAMPLE CALCULATIONS (BIAS, DRIFT, AND CORRECTED RAW AVERAGE)**

**System Bias**

RM 7E, (08-15-06), 12.3 System Bias. For non-dilution systems, use Equation 7E-2 to calculate the system bias separately for the low-level and upscale calibration gases. (calc for analyzer upscale gas, Run 1 initial bias, if applicable)

$$SB = \left(\frac{C_S - C_{Dir}}{CS}\right) \times 100$$ Eq. 7E-2

SB = (ppm - ppm) / ppm x 100 = %

**Drift Assessment**

RM 7E, (08-15-06), 12.5 Drift Assessment. Use Equation 7E-4 to separately calculate the low-level and upscale drift over each test run. (calc for analyzer upscale drift, Run 1, if applicable)

$$D = \left| SB_{final} - SB_i \right|$$ Eq. 7E-4

D = | % - % | = %

**Alternative Drift and Bias**

RM 7E, (08-15-06), 13.2 / 13.3 System Bias and Drift. Alternatively, the results are acceptable if |Cs – Cdir| is≤ 0.5 ppmv or if |Cs – Cv| is ≤ 0.5 ppmv (as applicable). (calc for analyzer initial upscale, Run 1, if applicable)

$$SB / D_{Alt} = \left| C_S - C_{Dir} \right|$$ Eq. Section 13.2 and 13.3

$SB / D_{Alt}$ = | ppm - ppm | = ppm

**Bias Adjusted Average**

RM 7E, (08-15-06), 12.6 Effluent Gas Concentration. For each test run, calculate Cavg, the arithmetic average of all valid concentration values (e.g., 1-minute averages). Then adjust the value of Cavg for bias, using Equation 7E-5. (calc for analyzer, Run 1, if applicable)

$$C_{Gas} = \left(C_{Avg} - C_O\right) \times \left(\frac{C_{MA}}{C_M - C_O}\right)$$ Eq. 7E-5

$C_{Gas}$ = ( ppm - ppm) x ( ppm / (ppm - ppm) ) = ppm

**EXAMPLE CALCULATIONS (BSFC)**

Using LHV with $Q_f$ (Btu/hp*hr)

$$BSFC\ (Btu / hp \cdot hr) = Q_f$$

BSFC = Btu / hp*hr = Btu / hp*hr

Using HHV with $Q_f$ (SCFH)

$$BSFC\ (Btu / hp \cdot hr) = \frac{HHV \times Q_f}{bhp}$$

BSFC = Btu / SCF x SCF / hr x 1 / hp = Btu / hp*hr

Using LHV with $Q_f$ (SCFH)

$$BSFC\ (Btu / hp \cdot hr) = \frac{LHV \times Q_f}{bhp}$$

BSFC = Btu / SCF x SCF / hr x 1 / hp = Btu / hp*hr

Using HHV with $Q_f$ (Btu/hp*hr)

$$BSFC\ (Btu / hp \cdot hr) = \frac{Q_f \times HHV}{LHV}$$

BSFC = N/A Btu / hp*hr x Btu / SCF x scf / Btu = Btu / hp*hr

**EXAMPLE CALCULATIONS (Emissions based on Table 29 values)**

**Emission Rate (lb/hr)**
**$Q_f$ (Btu/hp*hr))**

$$E(lb / hr) = \frac{E_{g / hp \cdot hr} \times bhp}{453.6}$$

E (lb/hr) = g / hp*hr x lb / 453.6 g x hp = lb / hr

**Emission Rate (g/hp-hr)**
**$Q_f$ (Btu/hp*hr))**

$$E(g / hp \cdot hr) = CRA \times Q_f \times FFactor \times MW \times \frac{1}{10^6} \times \frac{1}{10^6} \times \frac{453.6}{G} \times \frac{20.9\%}{20.9\% - CRA_{O_2}}$$

E (g/hp-hr) = ppm x Btu / hp*hr x SCF / MMBtu x lb / lb-mol x 1 parts / $10^6$ ppm x 1 MMBtu / $10^6$ Btu x 453.6 g / lb x lb-mol / SCF x 20.9% / (20.9% - %) = g / hp*hr

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

**EXAMPLE CALCULATIONS (RUNS)**

**Stack Exhaust Flow ($Q_S$) - RM19**

$$Q_S = \left(\frac{FFactor \times Q_f \times HHV}{1{,}000{,}000}\right) \times \left(\frac{20.9\%}{20.9\% - C_{Gas(O2)}}\right)$$

$Q_S = \frac{\text{SCF}}{\text{MMBtu}} \times \frac{\text{SCF}}{\text{hr}} \times \frac{\text{Btu}}{\text{SCF}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}} \times \left[\frac{20.90\%}{20.9\% - \quad \%}\right] =$ SCFH

**$NO_2$ Conversion Efficiency Correction**

RM 7E, (08-15-06), 12.8 NO2 - NO Conversion Efficiency Correction. If desired, calculate the total NOX concentration with a correction for converter efficiency using Equations 7E-8. (calc for non-bias corrected (raw) NOx gas, Run 1, if applicable)

$$NOx_{Corr} = NO + \frac{NOx - NO}{Eff_{NO2}} \times 100$$ Eq. 7E-8

$NOx_{Corr} =$ ppm $+ \frac{\text{ppm} - \quad \text{ppm}}{\%} \times 100 =$ ppm

**Moisture Correction**

RM 7E, (08-15-06), RM7E, (08-15-06), 12.10 Moisture Correction. Use Equation 7E-10 if your measurements need to be corrected to a dry basis. (calc for THC analyzer, Run 1, if applicable) Note: Calculations may not match as Run 1 results are typically also bias adjusted

$$C_D = \frac{C_W}{1 - B_{WS}}$$ Eq. 7E-10

$C_D = \frac{\text{ppmvw}}{1 -} =$ ppmvd

**Diluent-Corrected Polutant Concentration, $O_2$ Based**

RM 20, (11-26-02), 7.3.1 Correction of Pollutant Concentration Using O2 Concentration. Calculate the O2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right)$$ Eq. 20-4

$C_{adj} =$ ppm $\times \left(\frac{20.9\% - \quad \%}{20.9\% - \quad \%}\right) =$ ppm@%$O_2$

**Diluent-Corrected Polutant Concentration, $CO_2$ Based**

RM 20, (11-26-02), 7.3.2 Correction of Pollutant Concentration Using CO2 Concentration. Calculate the CO2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \frac{X_{CO2}}{C_{Gas(CO2)}}$$ Eq. 20-5

$C_{adj} =$ ppm $\times \frac{\%}{\%} =$

7.2 $CO_2$ Correction Factor. If pollutant concentrations are to be corrected to percent $O_2$ and $CO_2$ concentration is measured in lieu of $O_2$ concentration measurement, a $CO_2$ correction factor is needed. Calculate the $CO_2$ correction factor as follows: 7.2.1 Calculate the fuel specific $F_o$, as follows:

$$F_0 = \frac{0.209\, F_d}{F_c}$$ Eq. 20-2

$F_0 = \frac{0.209 \times \quad \text{SCF/MMBtu}}{\text{SCF/MMBtu}} =$

7.2.2. Calculate the $CO_2$ correction factor for correcting measurement data to percent oxygen, as follows:

$$X_{CO2} = \frac{20.9\% - AdjFactor}{F_0}$$ Eq. 20-3

$X_{CO2} = \frac{20.9\% - \quad \%}{} =$ %

**Diluent-Corrected Polutant Concentration Corrected to ISO Conditions**

40CFR60.335(b)(1), Conversion for conc. at ISO Conditions (68°F, 1 atm). Calculate, as follows: (calc for @% with Run 1 data, if applicable)

$$C_{ISO} = C_{Adj} \times \sqrt{\frac{P_r}{P_o}} \times e^{(19 \times (H_o - 0.00633))} \times \left(\frac{288}{T_a}\right)^{1.53}$$

$C_{ISO} =$ ppm@%$O_2$ $\times \left(\sqrt{\frac{\frac{\text{psig} + 14.69232\ \text{psi}}{0.01933677\ \text{psi/mm Hg.}}}{\frac{\text{psig} + \quad \text{psi}}{0.01933677\ \text{psi/mm Hg.}}}}\right) \times 2.718^{(19\times(\quad \text{lb/lb}-0.00633))} \times \left(\frac{288\ \text{K}}{\text{K}}\right)^{1.53} =$ ppm@% and ISO

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

## EXAMPLE CALCULATIONS (RUNS)

### Emissions Rate (lb/hr)

Calculation for pound per hour emission rate. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

$$E_{lb/hr} = \frac{ppm}{10^6\ ppm/part} \times \frac{SCFH \times \quad lb/lb\text{-}mol}{SCF/lb\text{-}mol} = \frac{lb}{hr}$$

### Emissions Rate (ton/year)

Calculation for tons per year emission rate based on 8760 hours per year. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{ton/yr} = \frac{E_{lb/hr} \times hr_{year}}{2000}$$

$$E_{ton/yr} = \frac{lb}{hr} \times \frac{hr}{year} \times \frac{ton}{2000\ lb} = \frac{ton}{year}$$

### Emissions Rate (lb/MMBtu)

RM 19, (07-19-06), 12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in ng/J (lb/million Btu). (calc for gas Run 1, if applicable)

**Oxygen Based**

12.2.1 Oxygen-Based F Factor, Dry Basis. When measurements are on a dry basis for both $O_2$ (%$O_2$d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}} \qquad \text{Eq. 19-1}$$

$$E_{lb/MMBtu} = \frac{ppm \times \quad SCF/MMBtu \times \quad lb/ppm{*}ft^3 \times 20.9\%}{20.9\% - \quad \%} = \frac{lb}{MMBtu}$$

**Carbon Dioxide Based**

12.2.4 Carbon Dioxide-Based F Factor, Dry Basis. When measurements are on a dry basis for both $CO_2$ (%$CO_2$d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}} \qquad \text{Eq. 19-6}$$

$$E_{lb/MMBtu} = \frac{ppm \times \quad SCF/MMBtu \times \quad lb/ppm{*}ft^3 \times 100\%}{\%} = \frac{lb}{MMBtu}$$

**Conversion Constant**

Convc for

$$Conv_c(lb/ppm \cdot ft^3) = \frac{\frac{MW}{G}}{10^6}$$

$$Conv_c = \frac{\frac{lb}{lb{\bullet}mole} \times \frac{lb{\bullet}mole}{SCF}}{10^6} = \frac{lb}{ppm\text{-}ft^3}$$

### Sulfur Dioxide Rate (lb/MMBtu), 40CFR60, App. A, RM 19, Eq. 19-25 (11/20/03)

$$SO_2(lb/MMBtu) = 0.97 \times K \times \frac{S(wt\%)}{GCV}$$

$$SO_2 = 0.97 \times \frac{2 \times 10^4\ Btu}{wt\%{\bullet}MMBtu} \times \frac{wt\%}{Btu/lb} = \frac{lb}{MMBtu}$$

### Emissions Rate (g/hp-hr)

Calculation for grams per horsepower-hour. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{g/hp\text{-}hr} = \frac{E_{lb/hr} \times 453.6}{mw \times 1314.022} \ or\ \frac{E_{lb/hr} \times 453.6}{hp}$$

$$E_{g/hp\text{-}hr} = \frac{lb}{hr} \times \frac{453.6\ g}{lb} \times \frac{1}{mw} \times \frac{mw}{1314.022\ hp} = \frac{g}{hp{*}hr}$$

$$E_{g/hp\text{-}hr} = \frac{lb}{hr} \times \frac{453.6\ g}{lb} \times \frac{1}{hp} = \frac{g}{hp{*}hr}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

**RM 7E, (08-15-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:**

ACE = Analyzer calibration error, percent of calibration span.
$B_{WS}$ = Moisture content of sample gas as measured by Method 4 or other approved method, percent/100.
$C_{Avg}$ = Average unadjusted gas concentration indicated by data recorder for the test run.
$C_D$ = Pollutant concentration adjusted to dry conditions.
$C_{Dir}$ = Measured concentration of a calibration gas (low, mid, or high) when introduced in direct calibration mode.
$C_{Gas}$ = Average effluent gas concentration adjusted for bias.
$C_M$ = Average of initial and final system calibration bias (or 2-point system calibration error) check responses for the upscale calibration gas.
$C_{MA}$ = Actual concentration of the upscale calibration gas, ppmv.
$C_O$ = Average of the initial and final system calibration bias (or 2-point system calibration error) check responses from the low-level (or zero) calibration gas.
$C_S$ = Measured concentration of a calibration gas (low, mid, or high) when introduced in system calibration mode.
$C_{SS}$ = Concentration of NOx measured in the spiked sample.
$C_{Spike}$ = Concentration of NOx in the undiluted spike gas.
$C_{Calc}$ = Calculated concentration of NOx in the spike gas diluted in the sample.
$C_V$ = Manufacturer certified concentration of a calibration gas (low, mid, or high).
$C_W$ = Pollutant concentration measured under moist sample conditions, wet basis.
CS = *Calibration span.*
D = Drift assessment, percent of calibration span.
$E_p$ = The predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response.
$Eff_{NO2}$ = $NO_2$ to NO converter efficiency, percent.
H = High calibration gas, designator.
L = Low calibration gas, designator.
M = Mid calibration gas, designator.
NOFinal = The average NO concentration observed with the analyzer in the NO mode during the converter efficiency test in Section 16.2.2.
NOxCorr = The NOx concentration corrected for the converter efficiency.
NOxFinal = The final NOx concentration observed during the converter efficiency test in Section 16.2.2.
NOxPeak = The highest NOx concentration observed during the converter efficiency test in Section 16.2.2.
$Q_{Spike}$ = Flow rate of spike gas introduced in system calibration mode, L/min.
$Q_{Total}$ = Total sample flow rate during the spike test, L/min.
R = Spike recovery, percent.
SB = System bias, percent of calibration span.
$SB_i$ = Pre-run system bias, percent of calibration span.
$SB_f$ = Post-run system bias, percent of calibration span.
SB / $D_{Alt}$ = Alternative absolute difference criteria to pass bias and/or drift checks.
SCE = System calibration error, percent of calibration span.
$SCE_i$ = Pre-run system calibration error, percent of calibration span.
$SCE_{final}$ = Post-run system calibration error, percent of calibration span.
Z = Zero calibration gas, designator.

**40CFR60.335(b)(1), (09-20-06), Nomenclature. The terms used in the equations are defined as follows:**

$P_r$ = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
$P_o$ = observed combustor inlet absolute pressure at test, mm Hg
$H_o$ = observed humidity of ambient air, g $H_2O$/g air
e = transcendental constant, 2.718
$T_a$ = ambient temperature, K

**Small Engine and FTIR Nomenclature. The terms used in the equations are defined as follows:**

bhp = brake horsepower
hp = horsepower
$Q_{sys}$ = system flow (lpm)
$Q_m$ = matrix spike flow (lpm)

**RM 19, (07-29-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:**

AdjFactor = percent oxygen or carbon dioxide adjustment applied to a target pollitant

$B_{wa}$ = Moisture fraction of ambient air, percent.

Btu = British thermal unit

$\%_C$ = Concentration of carbon from an ultimate analysis of fuel, weight percent.

$\%_{CO2d}$, $\%_{CO2w}$ = Concentration of carbon dioxide on a dry and wet basis, respectively, percent.

CIP / CDP = Combustor inlet pressure / compressor discharge pressure (mm Hg); note, some manufactures reference as PCD.

E = Pollutant emission rate, ng/J (lb/million Btu).

$E_a$ = Average pollutant rate for the specified performance test period, ng/J (lb/million Btu).

$E_{ao}$, $E_{ai}$ = Average pollutant rate of the control device, outlet and inlet, respectively, for the performance test period, ng/J (lb/million Btu).

$E_{bi}$ = Pollutant rate from the steam generating unit, ng/J (lb/million Btu).

$E_{bo}$ = Pollutant emission rate from the steam generating unit, ng/J (lb/million Btu).

$E_{ci}$ = Pollutant rate in combined effluent, ng/J (lb/million Btu).

$E_{co}$ = Pollutant emission rate in combined effluent, ng/J (lb/million Btu).

$E_d$ = Average pollutant rate for each sampling period (e.g.,24-hr Method 6B sample or 24-hr fuel sample) or for each fuel lot (e.g. amount of fuel bunkered), ng/J (lb/million Btu).

$E_{di}$ = Average inlet $SO_2$ rate for each sampling period d, ng/J (lb/million Btu).

$E_g$ = Pollutant rate from gas turbine, ng/J (lb/million Btu).

$E_{ga}$ = Daily geometric average pollutant rate, ng/J (lbs/million Btu) or ppm corrected to 7 percent $O_2$.

$E_{jo}$, $E_{ji}$ = Matched pair hourly arithmetic average pollutant rate, outlet and inlet, respectively, ng/J (lb/million Btu) or ppm correctedto 7 percent $O_2$.

$E_h$ = Hourly average pollutant, ng/J (lb/million Btu).

$E_{hj}$ = Hourly arithmetic average pollutant rate for hour "j," ng/J (lb/million Btu) or ppm corrected to 7 percent $O_2$.

EXP = Natural logarithmic base (2.718) raised to the value enclosed by brackets.

Fc = Ratio of the volume of carbon dioxide produced to the gross calorific value of the fuel from Method 19

$F_d$, $F_w$, $F_c$ = Volumes of combustion components per unit of heat content, scm/J (scf/million Btu).

$ft^3$ = cubic feet

G = ideal gas conversion factor
 (385.23 SCF/lb-mol at 68 deg F & 14.696 psia)

GCM = gross Btu per SCF (constant, compound based)

GCV = Gross calorific value of the fuel consistent with the ultimate analysis, kJ/kg (Btu/lb).

$GCV_p$, $GCV_r$ = Gross calorific value for the product and raw fuel lots, respectively, dry basis, kJ/kg (Btu/lb).

$\%_H$ = Concentration of hydrogen from an ultimate analysis of fuel, weight percent.

$H_b$ = Heat input rate to the steam generating unit from fuels fired in the steam generating unit, J/hr (million Btu/hr).

$H_g$ = Heat input rate to gas turbine from all fuels fired in the gas turbine, J/hr (million Btu/hr).

$\%_{H2O}$ = Concentration of water from an ultimate analysis of fuel, weight percent.

$H_r$ = Total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).

K = volume of combustion component per pound of component (constant)

K = Conversion factor, $10^{-5}$ (kJ/J)/(%) [$10^6$ Btu/million Btu].

$K_c$ = (9.57 scm/kg)/% [(1.53 scf/lb)/%].

$K_{cc}$ = (2.0 scm/kg)/% [(0.321 scf/lb)/%].

$K_{hd}$ = (22.7 scm/kg)/% [(3.64 scf/lb)/%].

$K_{hw}$ = (34.74 scm/kg)/% [(5.57 scf/lb)/%].

$K_n$ = (0.86 scm/kg)/% [(0.14 scf/lb)/%].

$K_o$ = (2.85 scm/kg)/% [(0.46 scf/lb)/%].

$K_s$ = (3.54 scm/kg)/% [(0.57 scf/lb)/%].

$K_{sulfur}$ = $2x10^4$ Btu/wt%-MMBtu

$K_w$ = (1.30 scm/kg)/% [(0.21 scf/lb)/%].

lb = pound

ln = Natural log of indicated value.

$L_p$, $L_r$ = Weight of the product and raw fuel lots, respectively, metric ton (ton).

$\%_N$ = Concentration of nitrogen from an ultimate analysis of fuel, weight percent.

$M_{\%}$ = mole percent

mol = mole

MW = molecular weight (lb/lb-mol)

$MW_{AIR}$ = molecular weight of air ( 28.9625 lb/lb-mole)[1]

NCM = net Btu per SCF (constant based on compound)

$\%_O$ = Concentration of oxygen from an ultimate analysis of fuel, weight percent.

$\%_{O2d}$, $\%_{O2w}$ = Concentration of oxygen on a dry and wet basis, respectively, percent.

$P_B$ = barometirc pressure, in Hg

$P_s$ = Potential SO2 emissions, percent.

$\%_S$ = Sulfur content of as-fired fuel lot, dry basis, weight percent.

$S_e$ = Standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).

$\%_{St}$ = Concentration of sulfur from an ultimate analysis of fuel, weight percent.

S(wt%) = weight percent of sulfur, per lab analysis by appropriate ASTM standard

$S_i$ = Standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).

$S_o$ = Standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).

$\%S_p$, $\%S_r$ = Sulfur content of the product and raw fuel lots respectively, dry basis, weight percent.

SCF = standard cubic feet

SH = specific humidity, pounds of water per pound of air

$t_{0.95}$ = Values shown in Table 19-3 for the indicated number of data points n.

$T_{amb}$ = ambient temperature, °F

W/D Factor = 1.0236 = conv. at 14.696 psia and
 68 deg F (ref. Civil Eng. Ref. Manual, 7th Ed.)

$X_{CO2}$=$CO_2$ Correction factor, percent.

$X_k$ = Fraction of total heat input from each type of fuel k.

# Calculations, Formulas, and Constants

The following information supports the spreadsheets for this testing project.

## Given Data:

Ideal Gas Conversion Factor = 385.23 SCF/lb-mol at 68 deg F & 14.696 psia

Fuel Heating Value is based upon Air Hygiene's fuel gas calculation sheet. All calculations are based upon a correction to 68 deg F & 14.696 psia

High Heating Values (HHV) are used for the Fuel Heating Value, F-Factor, and Fuel Flow Data per EPA requirements.

**ASTM D 3588**

| | |
|---|---|
| Molecular Weight of NOx (lb/lb-mole) = | 46.01 |
| Molecular Weight of CO (lb/lb-mole) = | 28.00 |
| Molecular Weight of SO2 (lb/lb-mole) = | 64.00 |
| Molecular Weight of THC (propane) (lb/lb-mole) = | 44.00 |
| Molecular Weight of VOC (methane) (lb/lb-mole) = | 16.00 |
| Molecular Weight of NH3 (lb/lb-mole) = | 17.03 |
| Molecular Weight of HCHO (lb/lb-mole) = | 30.03 |

**40CFR60, App. A., RM 19, Table 19-1**

| | |
|---|---|
| Conversion Constant for NOx = | 0.0000001194351 |
| Conversion Constant for CO = | 0.0000000726839 |
| Conversion Constant for SO2 = | 0.0000001661345 |
| Conversion Constant for THC = | 0.0000001142175 |
| Conversion Constant for VOC (methane) = | 0.0000000415336 |
| Conversion Constant for $NH_3$ = | 0.0000000442074 |
| Conversion Constant for HCHO = | 0.0000000779534 |

NOTE: units are lb/ppm*ft$^3$

## Formulas:

1. Corrected Raw Average ($C_{Gas}$). 40CFR60, App. A, RM 7E, Eq. 7E-5 (08/15/06)

$$C_{Gas} = \left(C_{Avg} - C_O\right) \times \left(\frac{C_{MA}}{C_M - C_O}\right)$$

2. Correction to % $O_2$, 40CFR60, App. A, RM 20, Eq. 20-5 (11/26/02)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right)$$

3. Emission Rate in lb/hr

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

4. Emission Concentration in lb/MMBtu ($O_2$ based)

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}}$$

5. Emission Concentration in lb/MMBtu ($CO_2$ based)

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}}$$

## RATA SHEET CALCULATIONS

d = Reference Method Data - CEMS Data

$S_d$ = Standard Deviation

CC = Confident Coefficient

n = number of runs

$t_{0.025}$ = 2.5 percent confidence coefficent T-values

RA = relative accuracy

ARA = alternative relative accuracy

BAF = Bias adjustment factor

| n | t | n | t | n | t |
|---|---|---|---|---|---|
| 2 | 12.706 | 7 | 2.447 | 12 | 2.201 |
| 3 | 4.303 | 8 | 2.365 | 13 | 2.179 |
| 4 | 3.182 | 9 | 2.306 | 14 | 2.160 |
| 5 | 2.776 | 10 | 2.262 | 15 | 2.145 |
| 6 | 2.571 | 11 | 2.228 | 16 | 2.131 |

1. Difference

$$d = \sum_{i=1}^{n} d_i$$

2. Standard Deviation

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

3. Confident Coefficient

$$CC = t_{0.025} \times \frac{S_d}{\sqrt{n}}$$

4. Relative Accuracy

$$RA = \frac{|d_{AVG}| + |CC|}{RM_{AVG}} \times 100$$

5. Alternative Relative Accuracy

$$ARA = \frac{|d_{AVG}| + |CC|}{AS} \times 100$$

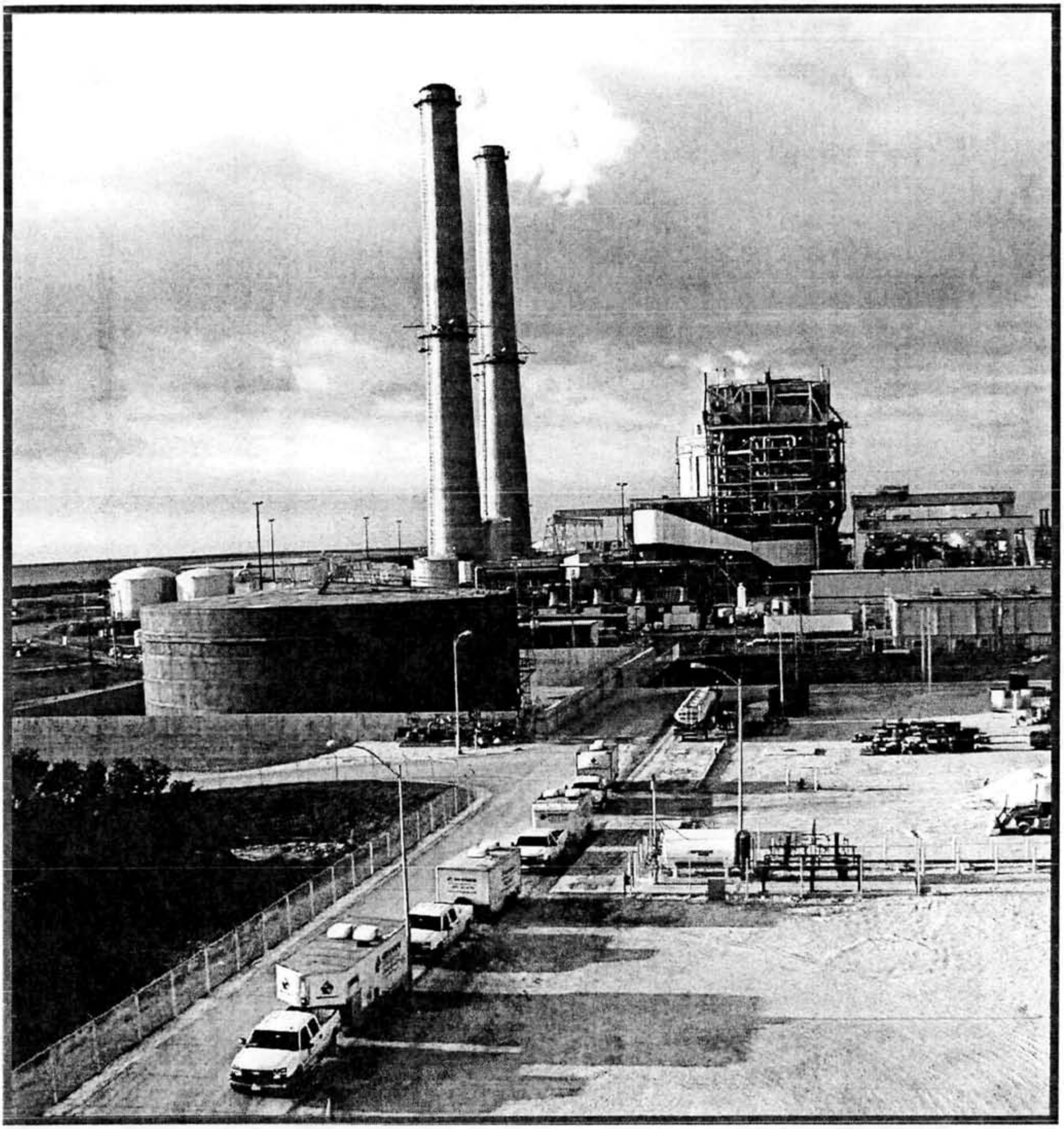
5. Bias Adjustment Factor

$$BAF = 1 + \left(\frac{|d_{AVG}|}{CEM_{AVG}}\right)$$

# APPENDIX E
# STATEMENT OF QUALIFICATIONS

Air Hygiene International, Inc. The Clear Choice

# STATEMENT OF QUALIFICATIONS – 2008



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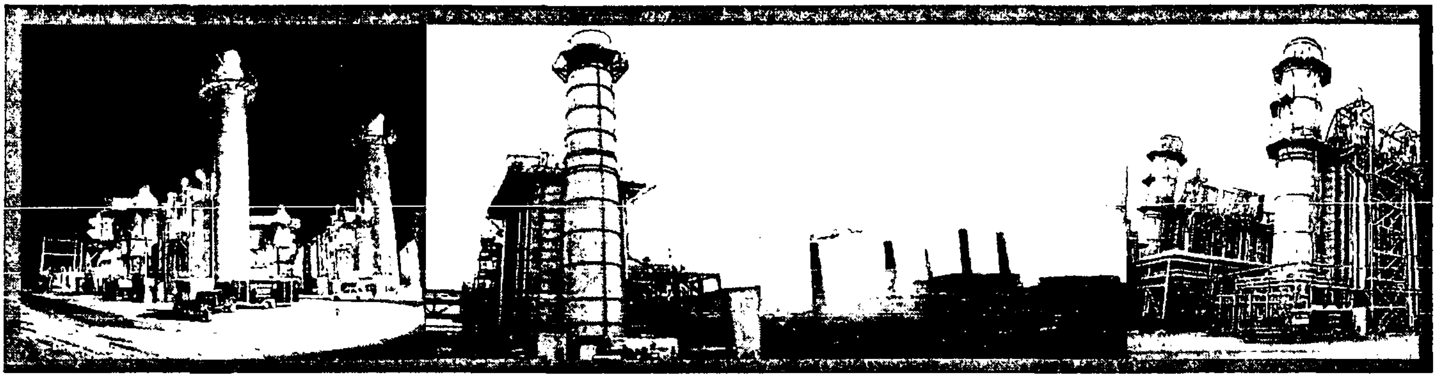


## STATEMENT OF QUALIFICATIONS

# AIR HYGIENE

### AIR EMISSION TESTING SERVICES

www.airhygiene.com

**May, 2008**

## INTRODUCTION

**AIR HYGIENE INTERNATIONAL, INC.** (**AIR HYGIENE**) is a professional air emission testing services firm operating from corporate headquarters in Tulsa, Oklahoma for over ten (10) years. Additional field offices with ready for field use testing labs are strategically located in Houston, Texas; Las Vegas, Nevada; and Philadelphia, Pennsylvania to serve all 50 United States, Mexico, and Canada. AIR HYGIENE specializes in air emission testing services for combustion sources burning multiple fuels with multiple control devices and supporting equipment.

AIR HYGIENE has testing laboratories which serve all fifty (50) of the United States and North America. Each mobile laboratory can be equipped with the following equipment and capabilities:

1. State-of-the-Art air emission analyzers, computers, and datalogging software. All designed into an efficient system to provide the fastest, most reliable information possible!
2. Dual racks for multiple source testing simultaneously or multiple points on a single source (in/out SCR, etc.)!
3. NIST traceable gases for the most accurate calibration. Ranges as low as 5 ppm!
4. $PM_{10}$, $NH_3$, mercury (Hg), sulfuric acid mist ($H_2SO_4$), $SO_3$, and formaldehyde sampling equipment!
5. VOC testing with on-board gas chromatograph to remove methane and ethane!
6. On-board printers to provide hard copies of testing information on-site!
7. Networking capabilities to provide real-time emission data directly into the control room!

AIR HYGIENE is known for providing professional services which include the following:

- Providing superior, cost saving services to our clients!
- High quality emission testing personnel with service oriented, friendly attitude!
- Meeting our client's needs whether it is 24 hour a day testing or short notice mobilization!
- Using great equipment that is maintained and dependable!
- Understanding the unique startup and operational needs associated with combustion turbines!

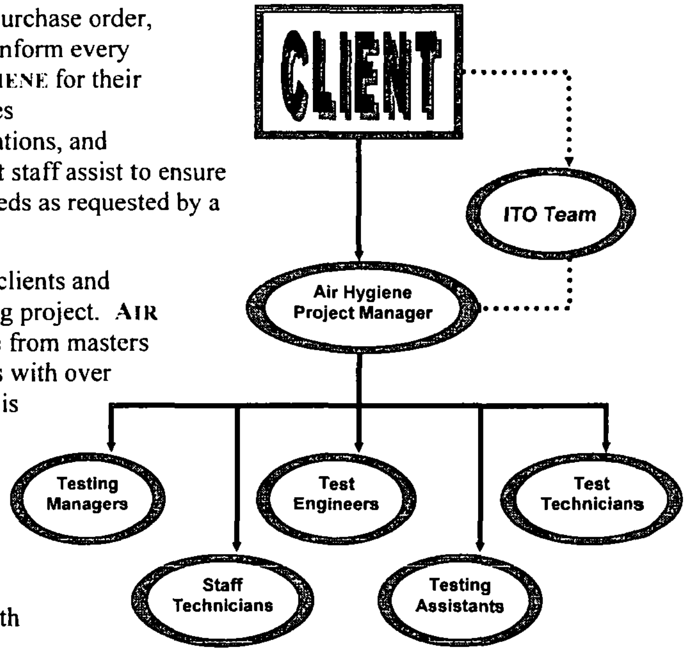
## MISSION STATEMENT

Our mission is to provide innovative, practical, top-quality services allowing our clients to increase operating efficiency, save money, and comply with federal/state requirements. We believe our first responsibility is to the client. In providing our unique services, the owners of AIR HYGIENE demand ethical conduct from each employee of the company. The character and integrity of AIR HYGIENE employees allows our clients to feel confidence in the air testing services of AIR HYGIENE. Through a long-term commitment to this mission, AIR HYGIENE is known as a company committed to improving our clients' operations.

AIR HYGIENE ... Does work worth paying for every time!
... Is well known for our emission testing services and uncompromising efforts to serve our clients!
... Does work that matters!
... Is proud of our emission testing capabilities!
... Provides exciting growth opportunities for energetic individuals!


# EMISSION TESTING TEAM

Air Hygiene International, Inc. (AIR HYGIENE) intends to exceed your expectations on every project. From project management to field-testing teams, we're committed to hard work on your behalf. The job descriptions and flowchart below outline AIR HYGIENE's client management strategy for your testing services.




From the initial request through receipt of the purchase order, the Inquisition To Order (ITO) team strives to inform every client of the benefits gained by using AIR HYGIENE for their emission testing project. The ITO team includes representatives from the sales, marketing, operations, and contracts divisions. In addition, several support staff assist to ensure the ITO team provides the support for client needs as requested by a client or project manager.

**Project Managers** are the primary contact for clients and ultimately responsible for every emission testing project. AIR HYGIENE's Project Managers experience range from masters level, professional engineers to industry experts with over 5,000 testing projects completed. Each project is assigned a Project Manager based primarily upon geographic location, then industry experience, contact history, and availability. The Project Manager prepares the testing strategy and organization for the project. This includes preparation of testing protocol; coordination with state agencies, client representatives, and any interested third parties. The site testing and report preparation are executed under the direction of the Project Manager from start to finish.

**Testing Managers** have completed Air Hygiene's rigorous demonstration of capability training program and are capable of operating all testing equipment and performing all test methods required for your testing project. Testing Managers assist Project Managers by leading the field testing when required, preparing draft reports, calibrating equipment, and overseeing testing team on-site.

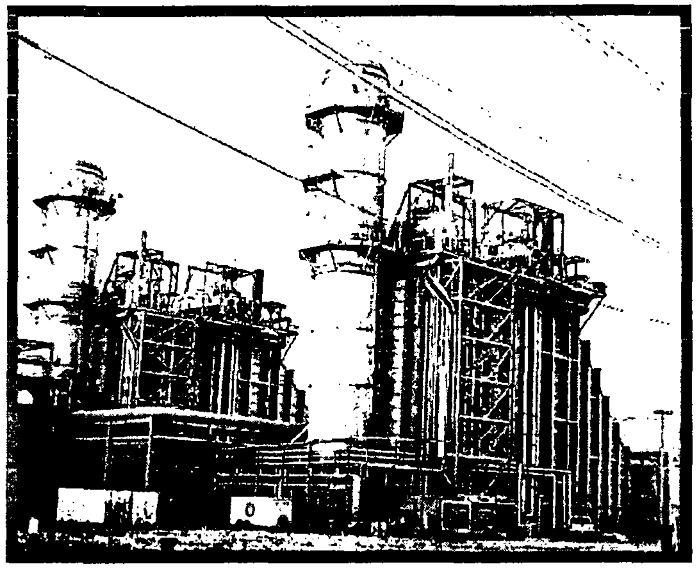
**Test Engineers** have significant background and understanding of emission testing or related services. Test Engineers prepare pre-test drawings for port location, ensure on-site logistics for electrical and mechanical/structural needs, and conduct on site testing as directed by the Project Manager and/or Testing Manager. Test Engineers often have special understanding of process and/or regulations applicable to specific testing jobs, which provide great value to both the client and Project Manager in testing strategies.

**Test Technicians** experience ranges from new hire with technical degree and experience to technicians who have performed up to 500 emission tests. All test technicians have a basic understanding of emission training and are involved in daily training and under supervision to continue to develop testing skills. Test Technicians have testing experience with AIR HYGIENE equipment along with a variety of industries and source equipment. Test Technicians may operate isokinetic sampling trains or gas analyzers on-site under the direction of the Project Manager and assist with preparation of field reports and quality assurance procedures.

**Staff Technicians** are entry-level personnel who have performed less than 500 emission tests. Staff Technicians perform pre-test equipment preparation, on-site test preparation, and testing assistance under the direction of Project Manager and/or Testing Manager. At least one Staff Technician is assigned to every project to assist on-site. Staff Technicians connect sampling probes to ports, assist with leak checks, raise and lower equipment to and from sampling platform, and other support activities under the direction of the Project Manager and/or Testing Manager.

**Testing Assistants** are entry-level personnel who have performed less than 100 emission tests. Testing Assistants help with equipment set-up, teardown, and simple testing procedures (i.e. move probe, fill ice bath, clean impingers, etc.) as directed.

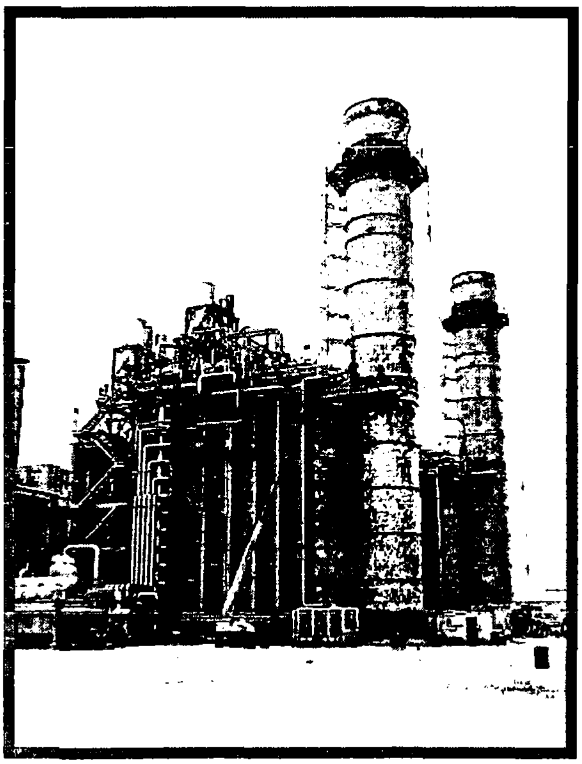
## AIR HYGIENE Emission Services Summary



Air Hygiene International, Inc. (AIR HYGIENE) is a privately-held professional services firm headquartered in Tulsa, Oklahoma with additional field offices in Las Vegas, Nevada, Houston, Texas; and Philadelphia, Pennsylvania. AIR HYGIENE specializes in emission testing services for a variety of industries including solid, liquid, & gas fired utility plants, turbines, engines, refineries, printers, glass plants, chemical plants, various manufacturers and related industries.

AIR HYGIENE provides turn-key emission testing services with fast-turnaround which include:

1. Pre-test site visit
2. Consulting on port locations and setup;
3. Preparation of test plan for state agency;
4. Coordination with state agency for emission testing;
5. On-site emission testing services; and
6. Preparation of draft and final reports.



AIR HYGIENE has mobile laboratories that serve all 50 United States and North America. AIR HYGIENE has performed over 15,000 emission tests on a variety of sources.

AIR HYGIENE performs air emission certification compliance testing on combustion sources (natural gas, coal, fuel oil, jet fuel, etc), NSPS sources, and Title V compliance sites. Our experience ranges from emission testing for new PSD facilities, MACT and RACT required performance certification testing to Relative Accuracy Test Audits (RATA Tests) for Continuous Emission Monitoring Systems (CEMS) and Parametric Emission Monitoring Systems (PEMS).

**Air Hygiene** has conducted numerous emission testing projects, which involved multiple groups relying upon instantaneous reporting of important test data. These projects relied upon **Air Hygiene's** SPIDER network. The SPIDER network provides Simultaneously Produced Information During Emission Readings (SPIDER) between the emission monitoring system and multiple locations (i.e. control room, test center, office, etc.). Hence, you can view real-time emission testing data on-demand from any location you choose using our wireless network data-logging system!

AIR HYGIENE performs FTIR testing by EPA Method 320 & 321 for Hazardous Air Pollutants (HAPS) including formaldehyde, benzene, xylene, toluene, hexane, ammonia, hydrogen chloride, etc. This methodology provides real-time analysis of these critical pollutants.

AIR HYGIENE specializes in the following types of pollutants and EPA Reference Methods (RM):

- Exhaust Flow – RM 2 &/or 19
- Carbon Dioxide ($CO_2$) – RM 3a
- Oxygen ($O_2$) – RM 3a &/or 20
- Moisture – RM 4
- Particulates (PM) – RM 5(filterable) & 202(condensable)
- PM < 10 microns ($PM_{10}$) – RM 201a
- PM < 2.5 microns ($PM_{2.5}$) – RM 201b
- *PM sizing (elzone analysis)*
- Sulfur Dioxide ($SO_2$) – RM 6c
- Nitrogen Oxides (NOx) – RM 7e &/or 20
- Sulfuric Acid Mist (SO3) – RM 8a (control condensate)
- Opacity – RM 9
- Carbon Monoxide (CO) – RM 10
- Hydrogen Sulfide ($H_2S$) – RM 11
- Lead – RM 12
- Dioxin & Furans – RM 23
- Total Hydrocarbons (THC) – RM 25a
- Volatile Organic Compounds (VOC) RM 25a & RM 18
- Metals – RM 29
- Chrome – RM 306
- Formaldehyde – RM 320 (FTIR), SW-846 0011, CARB 429
- HAPS – FTIR – RM 320 (FTIR)
- Ammonia – CTM-027 or BAAQMD ST-1B
- Mercury – Ontario Hydro Method, Sorbent Tubes (both with on-site analysis, RM 29, and starting in August, 2007 – instrumental Hg by Thermo Mercury Freedom System

## TESTING EXPERIENCE

AIR HYGIENE testing personnel account for more than sixty-five (65) years of testing experience and over 15,000 emission tests. Our testing services have involved dealings with all 50 state agencies and EPA regional offices. AIR HYGIENE testing personnel are rigorously trained on EPA reference test methods from 40 CFR Part 51, 60, 63, and 75 along with ASTM methods. All testing personnel are instructed and tested on test responsibilities and must complete a "Demonstration of Capability" test per the AIR HYGIENE Quality Assurance Manual and the AIR HYGIENE Emission Testing Standard Operating Procedures Handbook.

AIR HYGIENE has completed testing on over 200 power plants including in excess of 500 combustion turbines and 50 coal fired boilers 100,000 megawatts (MW). ***Let us add your project to our list of satisfied customers!***

## TESTING SUCCESS STORIES

AIR HYGIENE personnel have performed thousands of testing projects which have yielded significant benefits for our clients. The following project descriptions briefly discuss some of these emission testing projects.

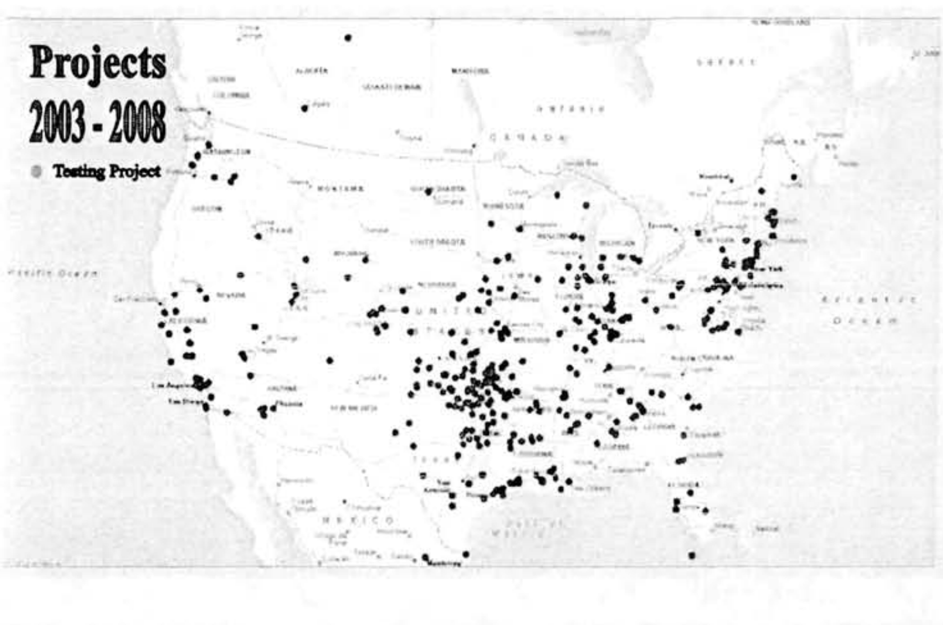
- Conducted Mercury (Hg), PM, selected metals, HCl, Chlorine, and gas testing to verify status with the industrial boiler MACT on six coal fired units at three (3) locations.
- Conducted inlet/outlet baghouse emission testing for Mercury (Hg) to determine control efficiency using Ontario-Hyrdo testing methodology.
- Conducted numerous projects optimizing SCR performance by conducting inlet & outlet SCR analysis for $NH_3$, NOx, flow, and Oxygen. Used information to assist with flow optimization and AIG tuning.
- Conducted federal and state required compliance testing for NOx, CO, PM-10 (front & back-half), $SO_2$, VOC, Ammonia, Formaldehyde, Opacity, RATA testing (NOx and CO) for new and updated power plants with both simple and combined cycle turbines firing natural gas and fuel oil.

- Conducted dry low NOx burner tuning and performance testing for various models of GE, Siemens Westinghouse, Mitsubishi, Pratt & Whitney, and ABB combustion turbines to verify manufacturer's emission guarantees for clients in preparation for compliance testing.
- Performed power plant emission testing for natural gas & fuel oil fired combustion turbines. Tests included federal required testing per 40 CFR Part 75, state air permit requirements, RATA testing, and emission testing to verify manufacturer's guarantee's during electric/heat output performance testing.

## TESTING LOCATIONS

AIR HYGIENE bases mobilization charges on the distance from your site to the closest of four (4) regional starting points covering all 50 United States. These include Las Vegas, Tulsa, Houston, and Philadelphia.

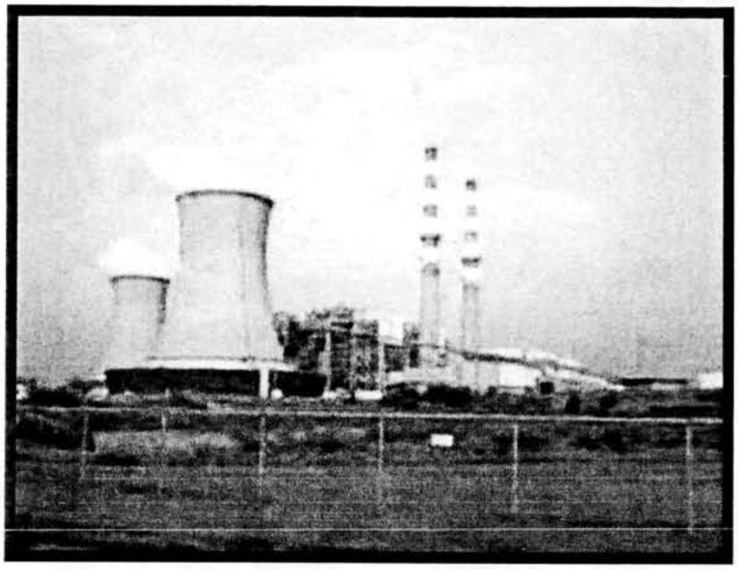
Each start point is located such that the AIR HYGIENE test teams can mobilize to your site within 24 hours at affordable costs to ensure we are price competitive to any U.S. location.



**COMBUSTION TESTING SERVICES SUMMARY**

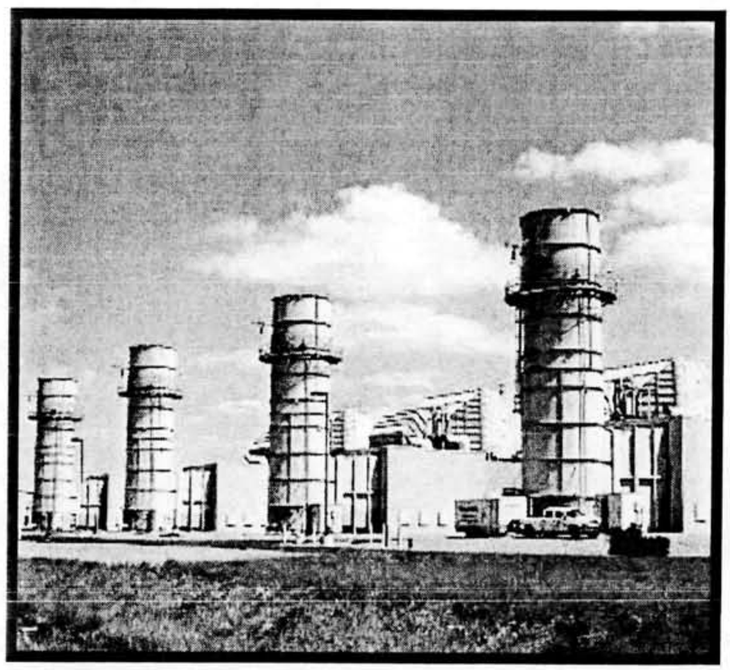
Thank you for your consideration of the combustion emission testing services of Air Hygiene International, Inc. (AIR HYGIENE). The following list details some of the testing services and extras AIR HYGIENE includes with each testing job.

Types of Air Testing Services for Combustion Sources:



- Boiler or Turbine tuning/mapping for NOx, CO, O2, CO2, flow, temperature, &/or $NH_3$ emissions
- Pollutant testing to verify EPC contractual emission guarantees
- Research and Development (R&D) emission data research and emissions optimization
- Mercury (Hg) testing with on-site data
- 40 CFR Part 60 Subpart GG or KKKK – Turbine Compliance Testing
- 40 CFR Part 75 – Acid Rain Classified Equipment Testing
- 40 CFR Part 75 Appendix E – Peaking Plant CEMS alternative NOx emissions versus Heat Input mapping
- RATA Testing on CEMS systems for NOx, CO, $SO_2$, $CO_2$ or $O_2$, Flow (3-D & Wall effects)
- QA/QC Plans, Monitoring Plans, Linearity Checks, Testing Protocols, etc. are provided with our high quality, service oriented emission testing services
- Initial permit compliance testing for PM, PM-10, PM-2.5, $SO_2$, NOx, CO, H2SO4, HCl, Hg, exhaust flow, moisture, $O_2$, $CO_2$, Ammonia, Formaldehyde, other HAPs

AIR HYGIENE will provide the following testing services:



- On-site, real-time test data
- Fuel F-Factor calculation data sheet
- Experienced emission testing personnel
- Flexible testing schedules to meet your needs
- Electronic reports provided on CD upon request
- Extensive experience with all 50 state agencies in the U.S., Mexico, & Canada
- EPA Protocol 1 Certified Gases (one percent accuracy) for precise calibration
- Low range (0-10 ppm) equipment calibration and measurement available
- Test protocol preparation, coordination with state agency, and site personnel
- Numerous mobile testing labs, which may be used for your projects across the U.S.
- State-of-the-art data logging technology to allow real-time examination of meaningful emission data
- Monitor your emissions data measured in our test lab from your control room via our datalogging network system

AIR HYGIENE is committed to providing testing teams that will take the time to meet your needs. We ensure the job is completed on time with the least amount of interruption to your job and site operation as possible. Thank you for considering our services.


AIR HYGIENE's Synergistic Approach to Power Plant Air Emissions Testing

Power plants continue to be built, modified, and improved across the United States. These new or modified facilities are at the forefront of clean energy. These units are very efficient yet environmentally friendly, and must be to meet the stringent requirements set forth by the Environmental Protection Agency (EPA) and relevant state agencies. Air Hygiene International, Inc. (AIR HYGIENE) has developed a unique strategy to help owners deal with these complicated requirements.

Unique Testing Strategy

AIR HYGIENE has developed a synergistic approach to assisting the various groups involved in the completion of a commissioning/startup unit or modification project. AIR HYGIENE strives to combine the multiple testing aspects involved with bringing a combustion unit to commercial service. By conducting the various emission tests required for a new combustion unit using one test company, the following benefits are a given:

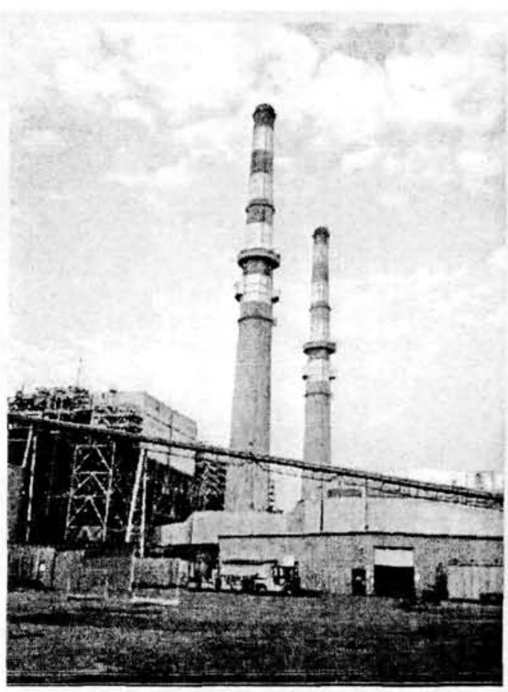

1. Save money by...
   a. Reduced mobilizations
   b. Combined tests yield reduced fuel usage and site time
   c. Bulk projects receive quantity discounts
2. Improve efficiency through familiarity with site needs
3. Site personnel and testing team are comfortable working together

These projects typically involve some or all of the following groups. There is not a defined set of responsibilities that will match every project. The table below simply suggests a typical list of testing responsibilities.

| **Responsible Party** | **Testing Responsibilities** |
|---|---|
| Owner | Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.) |
| Operator | Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.) |
| Turbine/Boiler manufacturer | Contractual emission guarantees of unit (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4) |
| EPC & Construction Company | Contractual emission guarantees including control devices (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4) |
| CEMS Supplier | Initial RATA testing (i.e. NOx, CO, SO2, CO2, O2, flow) |
| Lending Party (i.e. bank) | No responsibility, but concerned with outcome of all tests |
| Environmental Consultant | Concerned with air permit and overall compliance; may select the test contractor and provide oversight for testing |

Example Project:

A recent project provides a prime example of the synergistic benefits of using AIR HYGIENE to perform your commissioning/startup or remodification testing needs for performance and compliance. Eight GE Frame 7FA turbines were taken from performance testing through compliance testing in 20 days. The following tests were performed on each turbine:



- NOx tuning and mapping
- Contractual performance testing for NOx, CO, VOC, $SO_2$, $NH_3$, & $PM_{10}$
- 40 CFR Part 60 Subpart GG: testing for NOx and CO at max load
- 40 CFR Part 75: NOx & CO RATA certification on CEMS
- State required compliance testing for NOx, CO, VOC, $NH_3$(on-site analysis), formaldehyde (on-site analysis by FTIR), opacity and $SO_2$ burning natural gas

Test data was provided on-site for all tests, except PM-10. Electronic files were e-mailed for review to the turbine manufacturer, owner & operator, and environmental consultant within 24 hours following completion of site work. Complete reports including PM-10 were submitted to interested parties within 10 days following each blocks completion.

Power Plant Testing Experience

AIR HYGIENE personnel have over sixty-five (65) years of testing experience on combustion turbines, coal fired boilers, gas fired boilers, landfill gas, wood fired, & diesel fired engines across the United States. AIR HYGIENE has 10 combustion labs serving all 50 states from four permanent offices (Tulsa, OK; Houston, TX; Denver, CO; & Orlando, FL) and five mobilization points (Los Angeles, CA; Seattle, WA; Chicago, IL; Atlanta, GA; & Philadelphia, PA). AIR HYGIENE has tested plants ranging from 50 to 2,000 megawatts in both simple and combined cycle operation with controls including:

- Selective Catalytic Reduction - Ammonia injection
- Steam/Water injection
- Sprint injection
- Dry Low NOx burners (DLN)

AIR HYGIENE has completed testing at 134 plants on 315 combustion turbines, 21 coal fired boilers, 17 gas fired boilers, and others representing 64,876 megawatts (MW). AIR HYGIENE tested 5 power plants in 2000 and we have grown since testing 8 in 2001, 19 in 2002, 41 in 2003, and 52 in 2004. ***Let us add your upcoming project to our list of satisfied customers!***

**Air Hygiene International, Inc.** is a privately held professional service firm incorporated on March 1st, 1997. *Its mission is to reduce its client's exposures to regulatory, civil, and criminal liabilities related to air emissions through superior testing services, risk identification, and management services.* **Air Hygiene** accomplishes this mission by looking beyond mere compliance, toward strategies that encompass potential future liabilities as well as community responsibility.

Headquartered in Tulsa, Oklahoma, Air Hygiene serves clients throughout the continental United States as well as internationally. Its client base includes companies from various industries including oil and gas companies, utilities, manufacturers, and others.

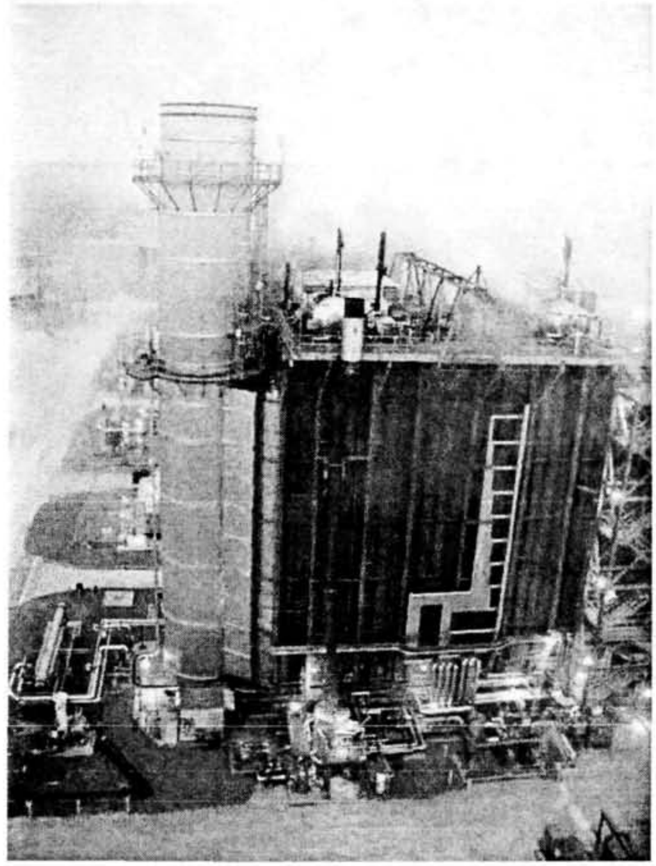
**Air Hygiene** has an experienced RATA testing teams led by project managers with significant testing experience and a broad understanding of the federal and state regulations. **Air Hygiene** has ten (10) RATA testing laboratories, each with on-board printers to allow on-site reporting of critical data for the client to review immediately following the testing.

If your site has testing needs such as an ammonia RATA by CTM-027 or Bay Area Method ST-1B, **Air Hygiene** will conduct the testing and provide the analysis on-site for immediate results for this important test.

*Our pricing and flexibility are second to no one.* **Air Hygiene** prides itself on testing efficiency. We can conduct your RATA in six (6) hours and efficiently move to the next unit and perform a second RATA during the same test day.

Need several units tested quickly? **Air Hygiene** frequently performs multiple RATA tests simultaneously. We have successfully performed as many as four (4) RATA tests simultaneously meeting 40 CFR Part 75 and Part 60 requirements.

Below are some of the companies with whom we've worked. If desired, we will provide our Statement of Qualifications, which details our references and our project experience. Please contact us for more information or a quick quotation for your next project!




## Air Hygiene International, Inc.

www.airhygiene.com
Toll-free (888) 461-8778




**Corporate Headquarters**
5634 S. 122nd E. Ave. Ste. F
Tulsa, OK 74146
(918) 307-8865

**Houston Office**
1920 Treble Drive, Suite E-5
Humble, TX 77338
(281) 540-5400

**Denver Office**
7315 South Revere Parkway, Ste 603
Centennial, CO 80112
(303) 790-0665

**Orlando Office**
PMB 303; 4250 Alafaya Trail, Suite 212
Oviedo, FL 32765
(407) 359-2297


**Additional Mobilization Points**: Philadelphia, Atlanta, Chicago, Los Angeles, and Seattle

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Headquartered in Tulsa, Oklahoma, Air Hygiene serves clients throughout the continental United States with additional offices in Houston, Texas; Denver, Colorado, and Orlando, Florida along with mobilization points in Los Angeles, California; Seattle Washington; Chicago, Illinois; Atlanta, Georgia; and Philadelphia, Pennsylvania. Its client base includes companies from various industries including oil and gas companies, utilities, manufacturers, and others.

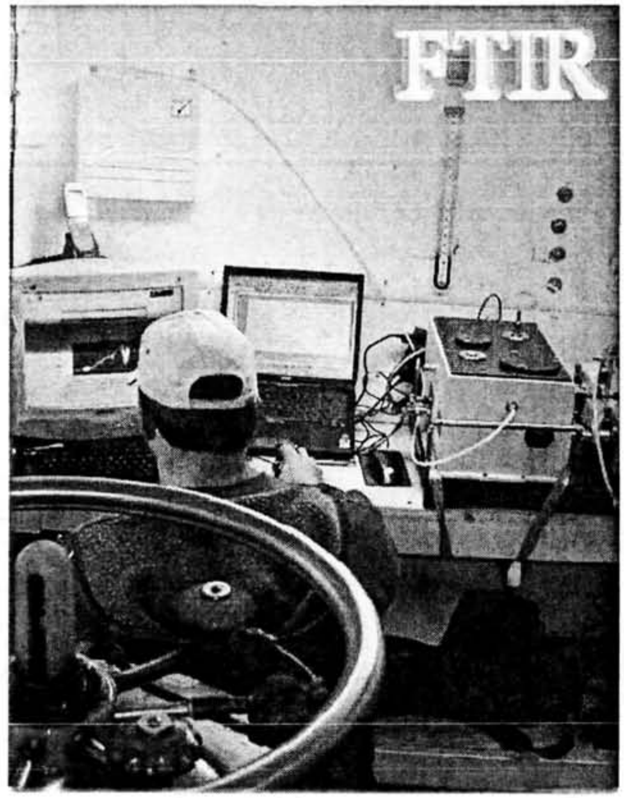
Air Hygiene has an experienced FTIR testing team lead by Thomas Graham, PE, Service Department Manager, and Mars Sharief, Lab Director.

**Thomas K. Graham,** PE, Service Department Manager, has taken part in several FTIR testing projects. One of the projects involved sampling multiple compounds at a waste water treatment plant to determine if the off-gassing would be effected by ambient temperature. The test was conducted during a warm period and a cold period for compounds including acetone, methylene chloride, methyl ethyl ketone, phenol, benzene, ethyl benzene, ammonia, toluene, o-xylene, m-xylene, and p-xylene. The utility sites tested include Blending Tank, Equalization Basin, Paint Chip Clarifier, Oil-Water Separator, and Storage Tank in the waste water treatment process. The open air processes were sampled with a flux chamber suspended on the water's surface and the other processes were sampled via ambient vents and vent extensions at the top of the tanks. The compounds measured ranged from ppb level to ppm level.

Mr. Graham possesses significant experience with project management for large projects involving stack testing in addition to other environmental engineering aspects. Mr. Graham has experience with air pollution control technologies, modeling, and emission chemistry. Mr. Graham has a Bachelor of Science degree in civil engineering, and a Masters of Science degree in environmental engineering from Oklahoma State University.

**Mars Sharief,** Lab Director, has worked on designing and testing air monitoring methods and applications with the FTIR. One of the projects involved testing formaldehyde from a combustion turbine in real-time with a detection limit of 40 ppb. To perform this test, the FTIR's detector and IR source were modified and a cold filter was added for high sensitivity measurements of formaldehyde. Mr. Sharief has a Bachelor of Science degree in chemical engineering with a minor in environmental engineering from the University of Tulsa.

Air Hygiene's FTIR lab meets all requirements of EPA 40 CFR Part 60 Appendix A, Reference Method 320 and the new MACT regulations found in EPA 40 CFR Part 63 Appendix YYYY. Air Hygiene's FTIR lab is available for testing at your plant for

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**Las Vegas Field Office**
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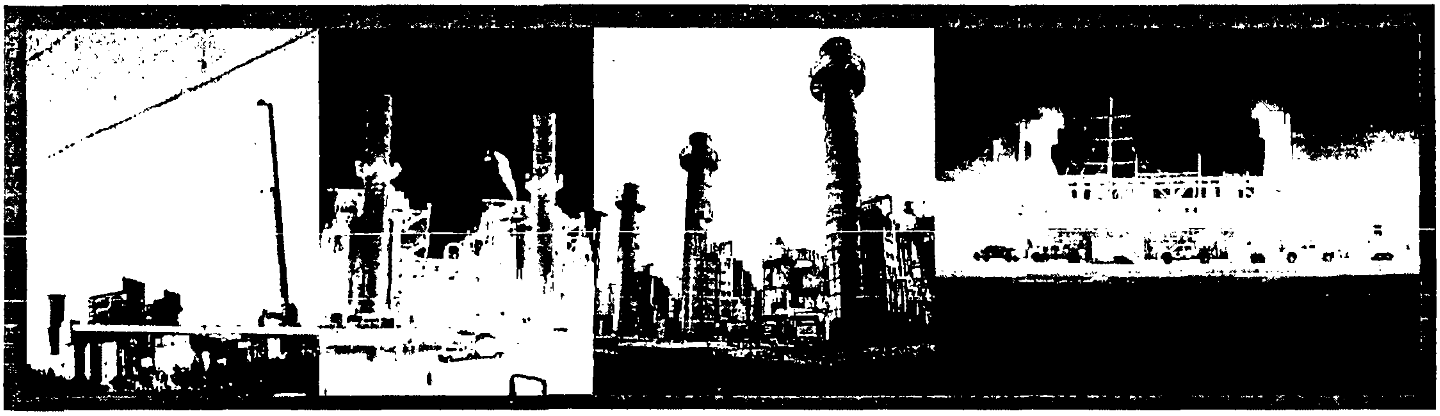
Las Vegas, NV 89156

**Philadelphia Field Office**
8900 State Road
Philadelphia, PA 19136



## INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures used by AIR HYGIENE during tests conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 3a, 6c, 7e, 10, 18, 19, 20, and 25a.

The flowchart on the next page depicts the sample system used by AIR HYGIENE for analysis of oxygen ($O_2$), carbon dioxide ($CO_2$), sulfur dioxide ($SO_2$), carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOC) tests. A heated stainless steel probe is inserted into the sample ports of the stack to extract gas measurements from the emission stream. The gas sample is continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample is partitioned to the $O_2$, $CO_2$, $SO_2$, CO, and NOx analyzers through glass and stainless steel rotameters that control the flow rate of the sample. The VOC sample is measured as a wet gas.

The flowchart shows that the sample system is also equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments are housed in an air-conditioned trailer which serves as a mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 is used to determine the cylinder concentrations where applicable (i.e. $NO_x$ calibration gases).

All data from the continuous monitoring instruments are recorded on a Logic Beach Hyperlogger which retrieves calibrated electronic data from each instrument every second and reports an average of the collected data every 30 seconds and 10 seconds. The averaging time can be selected to meet the clients needs. **This data is available instantaneously for printout, statistical analysis, viewable by actual values, or examined by a trending graph!**

The number of test runs, test loads, and length of runs is based upon federal and state requirements for the facility. Typical run times associated with emission testing are as follows:

| Type of Test | # of runs | Length of runs |
|---|---|---|
| $O_2$ Traverse (GG) | 1 run @ low load (8 – 48 points) | 2 minutes per point |
| NOx Stratification Test | 1 run @ base load (12 points) | 2 – 4 minutes per point |
| Subpart GG or KKKK | 3 runs @ 4 loads (30%, 50%, 75%, & 100%) | 15 – 60 minutes per run |
| RATA | 9 – 12 runs @ normal load | 21 minutes per run |
| State Permit Test (gases) | 3 runs @ base load | 1 hour per run |
| State Permit Test (particulates) | 3 runs @ base load | 2 – 4 hours per run |

The stack gas analysis for $O_2$ and $CO_2$ concentrations are performed in accordance with procedures set forth in EPA Method 3a (EPA Method 20 for $O_2$ on combustion turbines). The $O_2$ analyzer uses a paramagnetic cell detector. The $CO_2$ analyzer uses an infrared detector.

CO emission concentrations are quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer is used for this purpose.

NOx emission concentrations are measured in accordance with procedures set fort in EPA Method 7e and/or 20. A chemiluminescence analyzer is used to determine the nitrogen oxides concentration in the gas stream.

Total hydrocarbons (THC), non-methane, non-ethane hydrocarbons also known as volatile organic compounds (VOC) are analyzed in accordance with procedures set forth in EPA Methods 18 & 25a. A flame ionization detector calibrated with methane is used to determine the THC concentration in the gas stream and VOCs analyzed by GC to determine methane, ethane, and remaining VOCs per EPA Method 18 determination with gas chromatograph using FID detector.

# APPENDIX F
# AIR PERMIT

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400



**PERMITTEE:**

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

*Authorized Representative:*
Randall R. LaBauve, Vice President

FPL West County Energy Center
DEP File No. 0990646-001-AC
Permit No. PSD-FL-354
SIC No. 4911
Expires: December 31, 2011

**PROJECT AND LOCATION**

This permit authorizes the construction of two nominal 1,250 megawatt combined cycle units at the proposed Florida Power and Light Company (FPL) West County Energy Center.

The proposed project will be located at 20505 State Road 80, Loxahatchee, Florida 33470. This site encompasses 220 acres of which approximately 40 acres will be used for two combined cycle units.

UTM coordinates are Zone 17; 562.19 km E; 2953.04 km N.

**STATEMENT OF BASIS**

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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1/11/2007

Joseph Kahn, Director (Date)
Division of Air Resource Management

## FACILITY DESCRIPTION

The FPL West County Energy Center will be a nominal 2,500 megawatt (MW) greenfield power plant. The initial phase is the construction of two nominal 1,250 MW gas-fired combined cycle units that will use ultralow sulfur (ULS) fuel oil as backup fuel. The two combined cycle units are designated as Unit 1 and Unit 2.

Each combined cycle unit will consist of: three nominal 250 megawatt Model 501G gas turbine-electrical generator sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; one nominal 428 mmBtu/hour (LHV) gas-fired duct burner located within each of the three HRSG's; three 149 feet exhaust stacks; one 26 cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.

Additional ancillary equipment will include: four emergency generators; two natural gas fired fuel heaters; two diesel fuel storage tanks; two auxiliary steam boilers; and other associated support equipment.

*{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

## NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

| ID | Emission Unit Description |
|---|---|
| 001 | Unit 1A – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator |
| 002 | Unit 1B – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator |
| 003 | Unit 1C – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator |
| 004 | Unit 2A – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator |
| 005 | Unit 2B – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator |
| 006 | Unit 2C – one nominal 250 MW gas turbine with supplementary-fired heat recovery steam generator |
| 007 | Two nominal 6.3 million distillate fuel oil storage tanks* |
| 008 | Two 26 cell mechanical draft cooling towers |
| 009 | Two nominal 85,000 lb/hr (99.8 MMBtu/hr) auxiliary boilers |
| 010 | Two nominal 10 MMBtu/hr gas-fired process heaters |
| 011 | Four nominal 2,250 KW ( ~ 21 MMBtu/hr) emergency generators |
| 012 | One emergency diesel fire pump engine (< 300 hp) and 500 gallon fuel oil storage tank |

* This capacity will allow approximately 108 hours of on-site oil storage

## REGULATORY CLASSIFICATION

Title III: This facility will be major for hazardous air pollutants (HAPs).

Title IV: The facility will operate emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the new facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides ($NO_X$), particulate matter ($PM/PM_{10}$), sulfur dioxide ($SO_2$), and volatile organic compounds (VOC).

PSD: The facility is located in an area designated as "attainment," "maintenance," or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: This project is subject to applicable requirements of 40 CFR 60, NSPS-Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005). This project is also subject to applicable requirements of 40 CFR 60, NSPS-Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) and to 40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ICE).

NESHAPs: This project is subject to applicable requirements of 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. This project is also subject to applicable requirements of 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Reciprocating Internal Combustion Engines (RICE); and to 40 CFR 63, Subpart DDDDD National Emissions Standards for Industrial, Commercial, or Institutional Boilers and Process Heaters.

Siting: The facility is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

## PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

## COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Regulation Southeast District office (DEP-SED), 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401.

## APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Subparts A from NSPS 40 CFR 60 and NESHAP 40 CFR 63; Identification of General Provisions.

Appendix BD: Final BACT Determinations and Emissions Standards.

Appendix Dc: NSPS Requirements for Small Steam Generating Units, 40 CFR 60, Subpart Dc.

Appendix DDDDD: NESHAP Requirements for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD.

Appendix GC: General Conditions.

Appendix IIII: NSPS Requirements for Compression Ignition Internal Combustion Engines (ICE).

Appendix KKKK: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart KKKK.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix YYYY: NESHAP Requirements for Gas Turbines, 40 CFR 63, Subpart YYYY.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

## RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on April 14, 2005;
- Department PSD Application Sufficiency comments dated June 13, 2005;
- Sufficiency Responses received August 12, 2005;
- Letter from FPL to DEP dated December 29, 2005 regarding equipment selection, capacities, etc.;
- Draft permit package issued on March 1, 2006;
- FPL's comments on the Draft Permit and TEPD received March 31, 2006;
- Public Meeting comments received at the Royal Palm Beach Cultural Center on April 19, 2006 and by e-mails, telephone and letters;
- The Final Order of the Siting Board approving Certification dated December 26, 2006; and
- Final Determination distributed concurrently with Final PSD Permit.

## SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new units begin serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Application for Title V Permit: The permittee shall submit an application, pursuant to Chapter 62-213, F.A.C, for a Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

## SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

### A. COMBINED CYCLE UNITS 1 AND 2 – GAS TURBINES (EUs 001, 002, 003, 004, 005, and 006)

This section of the permit addresses the following emissions units.

**Combined Cycle Units 1 and 2 and associated equipment**

**Description**: Emissions units 001, 002, 003, 004, 005, and 006. Each emission unit consists of: a Model 501G combustion gas turbine-electrical generator set with automated gas turbine control, inlet air filtration system and evaporative cooling, a gas-fired heat recovery steam generator (HRSG) with duct burner, a HRSG stack, and associated support equipment. Each combined cycle unit is comprised of three of the described emission units. The project also includes two steam turbine-electrical generators, each of which serves a combined cycle unit.

**Fuels**: Each gas turbine fires natural gas as the primary fuel and ultra low sulfur distillate fuel oil as a restricted alternate fuel.

**Generating Capacity**: Each of the six gas turbine-electrical generator sets has a nominal generating capacity of 250 MW. Each of the two steam turbine-electrical generators has a nominal generating capacity of 500 MW. The total nominal generating capacity of each of the "3 on 1" combined cycle unit is approximately 1,250 MW. The total nominal generating capacity of the proposed project is 2,500 MW.

**Controls**: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, $PM/PM_{10}$, SAM, $SO_2$ and VOC. Dry Low-$NO_X$ (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system further reduces $NO_X$ emissions.

**Stack Parameters**: Each HRSG has a stack at least 149 feet tall with a nominal diameter of 22 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics without the duct burners:

| Fuel | Heat Input Rate (LHV) | Compressor Inlet Temp. | Exhaust Temp., °F | Flow Rate ACFM |
|---|---|---|---|---|
| Gas | 2,333 MMBtu/hour | 59° F | 195° F | 1,330,197 |
| Oil | 2,117 MMBtu/hour | 59° F | 293° F | 1,533,502 |

**Continuous Monitors**: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and $NO_X$ emissions as well as flue gas oxygen or carbon dioxide content.

**APPLICABLE STANDARDS AND REGULATIONS**

1. <u>BACT Determinations</u>: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides ($NO_X$), particulate matter ($PM/PM_{10}$), sulfuric acid mist (SAM), sulfur dioxide ($SO_2$) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. <u>NSPS Requirements</u>: The combustion turbines shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards given in 40 CFR 60, Subpart KKKK. Some separate reporting and monitoring may be required by the individual subparts.

   a *Subpart A, General Provisions*, including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests

- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

b *Subpart KKKK, Standards of Performance for Stationary Gas Turbines*: These provisions include standards for combustion gas turbines and duct burners.

3. NESHAP Requirements: The combustion turbines are subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY and Appendix A, NESHAP Subpart A of this permit).

**EQUIPMENT AND CONTROL TECHNOLOGY**

4. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain six Model 501G gas turbine-electrical generator sets each with a nominal generating capacity of 250 MW. Each gas turbine shall include an automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize DLN combustors. [Application; Design]

5. HRSGs: The permittee is authorized to install, operate, and maintain six new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the six gas turbines (1A to 1C and 2A to 2C) and deliver steam to one of the two steam turbine electrical generators. Each HRSG may be equipped with a gas-fired duct burner having a nominal heat input rate of 428 MMBtu per hour (LHV).

6. Gas Turbine/Supplementary-fired HRSG Emission Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN system to control $NO_X$ emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve sufficiently low CO and $NO_X$ values to meet the CO and $NO_X$ limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce $NO_X$ emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve sufficiently low CO and $NO_X$ values to meet the CO and $NO_X$ limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control $NO_X$ emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia ($NH_3$) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for $NO_X$ and $NH_3$ emissions.

   d. *Oxidation Catalyst*: The permittee shall design and build the project to facilitate possible future installation of oxidation catalyst system to control CO emissions from each gas combustion turbine/supplementary-fired heat recovery steam generator. The permittee may install the oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 12.h.

e. *Ammonia Storage:* In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Design; Rule 62-212.400(BACT), F.A.C.]

**PERFORMANCE RESTRICTIONS**

7. Permitted Capacity - Gas Turbines: The nominal heat input rate to each gas turbine is 2,333 MMBtu per hour when firing natural gas and 2,117 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
[Rule 62-210.200(PTE), F.A.C.]

8. Permitted Capacity - HRSG Duct Burners: The total nominal heat input rate to the duct burners for each HRSG is 428 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

9. Authorized Fuels: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil, during any calendar year.
[Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. Hours of Operation: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

11. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

    a. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a three-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

    b. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.

    c. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all six HRSGs) shall not exceed 7,395,840 MMBtu (LHV) during any consecutive 12 months.

    [Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

## A. COMBINED CYCLE UNITS 1 AND 2 – GAS TURBINES (EUs 001, 002, 003, 004, 005, and 006)

### EMISSIONS STANDARDS

12. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

| Pollutant | Fuel | Method of Operation | Stack Test, 3-Run Average | | CEMS Block Average |
|---|---|---|---|---|---|
| | | | ppmvd @ 15% $O_2$ | lb/hr [g] | ppmvd @ 15% $O_2$ |
| CO [a] | Oil | Combustion Turbine (CT) | 8.0 | 42.0 | 8.0, 24-hr<br>6, 12-month [h] |
| | Gas | CT & Duct Burner (DB) | 7.6 | 52.5 | |
| | | CT Normal | 4.1 | 23.2 | |
| $NO_X$ [b] | Oil | CT | 8.0 | 82.4 | 8.0, 24-hr |
| | Gas | CT & DB | 2.0 | 24.2 | 2.0, 24-hr |
| | | CT Normal | 2.0 | 20.0 | |
| $PM/PM_{10}$ [c] | Oil/Gas | All Modes | 2 gr S/100SCF of gas, 0.0015% sulfur fuel oil | | |
| | | | Visible emissions shall not exceed 10% opacity for each 6-minute block average. | | |
| $SAM/SO_2$ [d] | Oil/Gas | All Modes | 2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil | | |
| VOC [e] | Oil | CT | 6.0 | 19.6 | NA |
| | Gas | CT & DB | 1.5 | 5.4 | |
| | | CT Normal | 1.2 | 4.1 | |
| Ammonia [f] | Oil/Gas | CT, All Modes | 5 | NA | NA |

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner modes. The stacks test limits apply only at high load (90-100% of the combustion turbine capacity).

b. Compliance with the continuous $NO_X$ standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. $NO_X$ mass emission rates are defined as oxides of nitrogen expressed as $NO_2$.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for $PM/PM_{10}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the combustion turbine capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% $O_2$ limit for any combustion turbine/supplementary-fired heat recovery steam generator upon notification by the permittee of intent to install the oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. After completing the installation of the catalyst all prior partial or complete calendar months shall be excluded from the 12-month rolling average.

*{"DB" means duct burning. "SCR" means selective catalytic reduction. "NA" means not applicable}.*

[Rule 62-212.400(BACT), F.A.C.]

13. Duct Burners: The duct burners are also subject to the provisions of Subpart KKKK of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix KKKK.

*{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart KKKK for duct burners. Therefore, compliance with the BACT limits insures compliance with the emission limitations in Subpart KKKK.}* [40 CFR 60, Subpart KKKK]

**EXCESS EMISSIONS**

*{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}*

14. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

15. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

16. Definitions

a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
[Rule 62-210.200(245), F.A.C.]

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
[Rule 62-210.200(230), F.A.C.]

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

18. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed eight hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

       *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

    b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

    c. *Gas Turbine/HRSG System Cold Startup*: For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

    d. *Fuel Switching*: For fuel switching, excess emissions shall not exceed 2 hours in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines.
    [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
    [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

21. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} |
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.} |
| 18 | Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.} |
| 20 | Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines |
| 25A | Determination of Volatile Organic Concentrations |

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at www.epa.gov/ttn/emc/ctm.html The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department.
[Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, $NO_X$, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Referenced method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and $NO_X$ standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and $NO_X$ mass rate emissions standards. CO and $NO_X$ emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc.
[Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

23. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and $NO_X$ emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and $NO_X$ limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

24. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. $NO_X$ and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and $NO_x$ standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. $NO_X$ emissions recorded by the CEMS shall

be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

*{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}*

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

**CONTINUOUS MONITORING REQUIREMENTS**

25. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and $NO_X$ from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or $NO_X$ standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

    b. *$NO_X$ Monitors.* Each $NO_X$ monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the $NO_X$ monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent Monitors.* The oxygen ($O_2$) or carbon dioxide ($CO_2$) content of the flue gas shall be monitored at the location where CO and $NO_X$ are monitored to correct the measured emissions rates to 15% oxygen. If a $CO_2$ monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEM Data Requirements:

    a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and $NO_X$ as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

*{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and $NO_X$ emissions depending on the use of alternate methods of operation}*

d. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 17 and 18 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

27. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document

and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing $NO_X$ emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During $NO_X$ monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

**RECORDS AND REPORTS**

28. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

30. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

   a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

   b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

   c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart KKKK, excess emissions from the gas turbine are defined as: a specified averaging period over which either the $NO_X$ emissions are higher than the applicable emission limit in 60.4320; or the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in 60.4330. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

   *{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

   [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.4420]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.

## B. DISTILLATE FUEL OIL STORAGE TANK (EU 007)

*This section of the permit addresses the following emissions unit.*

| ID | Emission Unit Description |
|---|---|
| 007 | Two Nominal 6.3 million gallon distillate fuel oil storage tanks |

### NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb,. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

   The listed emission units shall comply with 40 CFR 60, Subpart Kb only to the extent that the regulations apply to the emission unit and its operations.

### EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain two 6.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

### EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

### NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective MSDS for the ultra low sulfur fuel oil(s) stored in the tanks. [62-4.070(3) F.A.C.]

   *{Permitting Note: An evaluation of several Material Safety Data Sheets (MSDS) by the Department and applicant demonstrated that the vapor pressure is much less than 3.5 kPa for ultralow sulfur fuel oil.}*

## C. COOLING TOWER (EU 008)

This section of the permit addresses the following new emissions unit.

| ID | Emission Unit Description |
|---|---|
| 008 | Two 26-cell mechanical draft cooling towers |

### EQUIPMENT

1. Cooling Tower: The permittee is authorized to install two new 26-cell mechanical draft cooling towers with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

### EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   *{Permitting Note: This work practice standard is established as BACT for PM/$PM_{10}$ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of $PM_{10}$ per year. Actual emissions are expected be lower than these rates.}.*

## D. AUXILIARY BOILERS AND PROCESS HEATERS (EU009 – EU 010)

This section of the permit addresses the following emissions units.

| ID | Emission Unit Description |
|---|---|
| 014 | Two limited use gas-fueled auxiliary boilers (99.8 MMBTU/h and 85,000 lb/hr) |
| 015 | Two gas-fueled 10 MMBtu/hr process heaters |

### NESHAP APPLICABILITY

1. NESHAP Subpart DDDDD Applicability: These emissions units are subject to Subpart DDDDD, which applies to an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 40 CFR 63.2.

   The listed emission units shall comply with 40 CFR 63, NESHAP Subpart DDDDD only to the extent that the regulations apply to the emission unit and its operations (e.g. limited use gas-fueled or small gas-fueled categories.

   [40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater]

### NSPS APPLICABILITY

2. NSPS Subpart Dc Applicability: Each 99.8 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].

### EMISSIONS AND TESTING REQUIREMENTS

3. Auxiliary Boiler BACT Emissions Limits:

| $NO_X$ | CO | VOC, $SO_2$, PM/$PM_{10}$ |
|---|---|---|
| 0.05 lb/MMBtu | 0.08 lb/MMBtu | 2 gr S/100SCF natural gas spec and 10% Opacity |

4. Auxiliary Boilers Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, $NO_X$ and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 63.7]

   Test Methods: Any required tests shall be performed in accordance with the following reference methods.

| Method | Description of Method and Comments |
|---|---|
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources<br>{Notes: The method shall be based on a continuous sampling train.} |

5. Annual CO Performance Test for Auxiliary Boilers: Pursuant to 40 CFR 63.7515(e) permittee shall conduct an annual CO test according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

   [40 CFR 63.7515 and Rule 62-204.800(11)(b)84. F.A.C.]

6. Natural Gas Fired Process Heaters BACT Emissions Limits:

| $NO_X$ | CO | VOC, $SO_2$, PM/$PM_{10}$ |
|---|---|---|
| 0.095 lb/MMBtu | 0.08 lb/MMBtu | 2 gr S/100SCF natural gas spec and 10% Opacity |

7. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, $NO_X$ and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

   Test Methods: Any required tests shall be performed in accordance with the following reference methods.

| Method | Description of Method and Comments |
|---|---|
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources<br>{Notes: The method shall be based on a continuous sampling train.} |

**EQUIPMENT SPECIFICATIONS**

8. Equipment: The permittee is authorized to install, operate, and maintain two auxiliary boilers with a maximum design heat input of 99.8 MMBtu/hr (85,000 lb/hr) each to produce steam during start up of the CTs and two 10 MMBtu/hr process heaters for the purpose of heating the natural gas supply to the CTs. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

**PERFORMANCE REQUIREMENTS**

9. Hours of Operation: The hours of operation of each limited use gas-fueled auxiliary boiler shall not exceed 500 hours per year. The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C. and 40 CFR 63.7575]

**NOTIFICATION, REPORTING AND RECORDS**

10. Notification: Initial notification is required for the two limited use 99.8 MMBtu/hr gas-fueled auxiliary boilers. Initial notification is not required for the two small gas-fueled 10 MMBtu/hr process heaters. [40 CFR 63.9, 40 CFR 63.7506(c) and Rule 62-204.800(11)(b) F.A.C.]

11. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters and auxiliary boilers. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

## EMERGENCY GENERATOR (011)

This section of the permit addresses the following emissions unit.

| ID | Emission Unit Description |
|---|---|
| 011 | Four nominal 2,250 Kw Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines |

### NESHAPS APPLICABILITY

1. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and are subject to 40 CFR 63, Subpart ZZZZ. They shall comply with 40 CFR 63, NESHAP Subpart ZZZZ only to the extent that the regulations apply to the emissions unit and its operations.

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

### NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and are subject to 40 CFR 60, Subpart IIII. They shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emission unit and its operations (e.g. non-road, emergency, displacement, capacity, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

### EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain four 2,250 Kw emergency generators. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

### EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per each generator. The generators are allowed to burn 0.0015% sulfur fuel oil.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Emergency Generators BACT Emissions Limits:

| $NO_X$ | CO | Hydrocarbons[1] | $SO_2$ | $PM/PM_{10}$ |
|---|---|---|---|---|
| 6.9 gm/bhp-hr | 8.5 gm/bhp-hr | 1.0 gm/bhp-hr | 0.0015% S F.O. | 0.4 gm/bhp-hr |

   Note 1. Hydrocarbons are surrogate for VOC.

   {The BACT limits are equal to the values corresponding to the Tier 1 values cited in the proposed rule 40 CFR 60, Subpart IIII}

6. Emergency Generators Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, $NO_X$ and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, an EPA Certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values and the use of ULS fuel oil can be used to fulfill this requirement.
   [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4211]

Test Methods: Any required tests shall be performed in accordance with the following reference methods.

| Method | Description of Method and Comments |
|---|---|
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources<br>{Notes: The method shall be based on a continuous sampling train.} |

**NOTIFICATION, REPORTING AND RECORDS**

7. Notifications: Initial notification are required pursuant to 40 CFR 60.7, 40 CFR 63.9, and 40 CFR 63.6590 (b) (i) for the four 2,250 Kw RICE units.

8. Reporting: The permittee shall maintain records of the amount of liquid fuel used. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.].

## EMERGENCY FIRE PUMP (012)

This section of the permit addresses the following emissions unit.

| ID | Emission Unit Description |
|---|---|
| 012 | One emergency diesel fire pump engine (< 300 hp) and 500 gallon fuel oil storage tank. |

### NSPS APPLICABILITY

1. NSPS Subpart IIII Applicability: The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and is subject to 40 CFR 60, Subpart IIII. It shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.]

### EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (< 300 hp) and an associated 500 gallon fuel oil storage tank.

### EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The fire pump may operate in response to emergency conditions and 80 non-emergency hours per year for maintenance testing.
   [Applicant Request; Rule 62-210.200 (PTE), F.A.C.]

4. Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

   Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

5. Fire Pump Engine BACT Emissions Limits:

   The following limits apply based on the size category of the fire pump located at the facility.

| Size (hp) | CO | $NMHC+NO_X$ | PM |
|---|---|---|---|
| $175 \leq hp < 300$ | 2.6 | 7.8 | 0.40 |

   Note 1. Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

   {The BACT limits are equal to the values corresponding to the size class indicated above and cited in 40 CFR 60, Subpart IIII}

6. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]