REPORT

TITLE V PERMIT REVISION APPLICATION

Request for Permanent Hydrated Lime Injection System
Crystal River North Power Plant
Facility ID No. 0170004

Submitted To: Air Quality Division
Department of Environmental Protection
2600 Blair Stone Road
MS 5000
Tallahassee, FL 32399

Submitted By: Golder Associates Inc.
5100 W. Lemon Street, Suite 208
Tampa, FL 33609 USA

Distribution: 4 Copies—Florida Department of Environmental Protection
1 Copy—Duke Energy Florida
1 Copy—Golder Associates Inc.

November 2013 **1302150**

Table of Contents

PART I—APPLICATION REPORT

List of Figures

List of Appendices

PART II—FDEP APPLICATION FOR AIR PERMIT

1.0 INTRODUCTION

Duke Energy Florida, Inc. (DEF) is submitting this application for a Title V (TV) permit revision for the Crystal River Energy Complex (CREC). Specifically, this application serves to incorporate the conditions of the air construction permit associated with the permanent hydrated lime injection system into a revised TV permit for Crystal River Units 4 and 5 (Crystal River North or CRN). In addition, the application requests incorporation of the final revised CO BACT limit into the TV revision.

DEF's CREC is located in Citrus County, Florida. Units 4 and 5 are fossil fuel-fired electric utility steam generators with dry bottom, wall fired boilers rated at 760 megawatts (MW), with a heat input capacity of 7,200 MMBtu/hr. The boilers are capable of burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil. No. 2 oil can be used as a startup fuel, and natural gas can be used for startup and for low-load flame stabilization. Air pollution control equipment includes: low-NOx burners, an SCR system, an acid mist mitigation (AMM) system, an ESP, and a FGD system. Flue gas exhausts through the stack at ~130 ºF. The AMM system is used for the control of SAM emissions and uses hydrated lime as the sorbent for primary control and ammonia injection as the method of secondary (backup) control.

In early 2011, DEF requested authorization for the temporary installation and operation of a demonstration injection system at Crystal River North using alternative sorbents to evaluate additional methods for reducing SAM emissions. Authorization was issued May 16, 2011 by the Florida Department of Environmental Protection (FDEP) through a revision to Permit No. PSD-FL-383D (FDEP Project No. 0170004-026-AC). Subsequently, Permit No. 0170004-037-AC (PSD-FL-383F), revised permit No. 0170004-026-AC to authorize a permanent hydrated lime injection system at Units 4 and 5. The construction activities that were authorized under this permit have now been substantially completed and compliance has been demonstrated.

Therefore, this application serves to incorporate the conditions of the air construction permit associated with the permanent hydrated lime injection system into a revised TV permit for Crystal River Units 4 and 5. In addition, the application requests incorporation of the final revised CO BACT limit into the TV revision. The air permit application consists of the appropriate application form required by the FDEP, Form 62-210.900(1), effective 3/11/2010 (see Part II of this application package). This air application report is divided into the following major sections:

- Section 1.0 provides the Project background;
- Section 2.0 provides a description of the Project;
- Section 3.0 provides a summary of the compliance demonstration required for this TV revision request; and
- Appendix A -- Project Figures.

2.0 PROJECT DESCRIPTION

This permitting action allows for permanent operation of a hydrated lime [$Ca(OH)_2$] injection system for SAM control. DEF selected hydrated lime as the best available sorbent because of ease of material handling, as well as the extent to which it has been used in the US. Hydrated lime has also been used on some of DEF's generating units in North Carolina with encouraging results.

The use of hydrated lime, which has been successfully demonstrated at Crystal River, will also have the co-benefit of reducing the level of ammonia (NH_3) in the fly ash. Eliminating the need for NH_3 for SAM mitigation significantly reduces the amount of NH_3 compounds retained with the fly ash. This has the benefit of improving handling and storage operations, as well as the beneficial reuse of the fly ash.

Additional detail on this permanent installation project is presented in the attached appendix. Appendix A consists of Figures 1 through 4, depicting a site map, the project location, sorbent injection point locations and the permanent sorbent injection system, respectively. This permanent system is proposed to be used in lieu of the current NH_3 injection system for control of SAM emissions, although the current NH_3 injection system will be retained for backup.

The sorbent is transported from the sorbent silo to the injection point(s) in the flue gas stream via a pneumatic conveying system. The locations of the permanent dry sorbent injection points include a combination of locations (e.g., SCR outlet, air heater outlet, ESP outlet) to optimize the system, as shown in Figure 3.

Figure 4 presents an overview of the dry sorbent storage and pneumatic conveying equipment associated with the permanent injection system. As shown in Figure 4, there is a new air emission source associated with the dry sorbent storage and injection system for each of the two steam units, for a total of two new emission points. These new sources are related to potential emissions that occur when displaced air entrains dust particles as the sorbent storage vessels are filled. To minimize these emissions, the exhaust from the storage vessels and the pneumatic conveyor are routed through fabric filters prior to exhausting to the ambient air; thus the fabric filters associated with each silo for each unit are the only new emission points. Each silo has dedicated rotary valves and blowers for pneumatic delivery of the sorbent to sets of lances mounted in flue gas ducts at various locations. The sorbent storage system has an estimated flow rate of 2,000 standard cubic feet per minute (scfm) through the dust collection system during loading operations, which is estimated to occur for six hours per day.

The sorbent injection rates will vary based on emission control levels and operational parameters at each of the sorbent injection locations. The sorbent reacts with the acidic compounds in the flue gas stream to form particulate matter that is further removed in the ESP and/or in the wet scrubber.

The emission estimates associated with material handling from the sorbent storage and transfer system assume year-round operation and are therefore considered to be a conservative estimate of potential emissions. The baghouse control system is designed to a particulate emissions design rate of 0.015 grains per standard cubic feet of exhaust gas flow.

The bag filters in the design specification ensure compliance with the visible emissions standard of less than 5 percent opacity when averaged over a six-minute period. In addition, the project will not cause or allow fugitive dust emissions to cause or contribute to substantive complaints or excess visible emissions beyond the property boundary. Haul roads and material handling operations are maintained in a manner that will minimize fugitive dust emissions.

The potential emissions from the permanent sorbent storage and injection systems for Units 4 and 5 at Crystal River are considered to be insignificant since the proposed activity emits less than 5 tons per year (TPY) of any criteria pollutant. New source review for the proposed project was not triggered since the potential to emit (PTE) $PM_{2.5}$ emission estimate is less than the 10 tons per year emission increase threshold.

3.0 COMPLIANCE DEMONSTRATION

The air construction permit for the hydrated lime injection system specified that various actions, notifications and reports be completed to demonstrate compliance, as part of this TV revision request. This permit application package, therefore, includes the completed FDEP Form No. 62-210.900(1), and all required supplemental material (e.g., compliance test reports, standard operating protocols, a CAM Plan, site location map, process schematics, unregulated and insignificant activities, etc.).

With respect to the SAM emission control system (AMM system), periods of startup, maintenance and repair are addressed differently. Previous permit language (Specific Condition B.15b) was meant to address situations when the AMM system would not be operable, assuming that there would be no backup control. Therefore, there is language requiring specific SAM testing while burning compliance coal to ensure that an operating option existed that was appropriate for these operating modes. However, the current configuration envisions the hydrated lime injection system as the primary means of SAM emissions control, with the previously used ammonia injection system retained as the backup system. This is addressed in the revision submittal in the attachment that requests TV permit language revisions.

The hydrated lime injection system, described in the air construction permit as Emission Unit No. 032, consists of the hydrated lime storage and transfer system. The hydrated lime injection system and miscellaneous ancillary equipment, as constructed, were evaluated for consistency with the proposed construction that was described in the construction permit. The system was found to have been constructed as previously described. This permanent system is proposed to be used in lieu of the current ammonia injection system, although the current system will be retained for backup.

3.1 SAM Stack Testing

As part of this project, and in accordance with Air Permit No. 0170004-037-AC, Specific Condition No. A.16, as issued by the FDEP, DEF conducted a series of preliminary performance tests on Units 4 and Unit 5 to determine SAM emissions rates under a variety of unit operating conditions in order to refine the injection rates when operating with the permanent system. In addition, Specific Condition A.19 required that compliance testing be conducted when the performance and tuning testing had been completed.

The hydrated lime AMM system performance testing was conducted on Crystal River Units 4 and 5 on August 26, 2013 through August 31, 2013. Additional hydrated lime AMM system tuning and optimization was conducted on October 8, 2013 and October 9, 2013. The injection rates for compliance testing were based on results from performance testing and refined following the tuning of the hydrated lime AMM system. Annual compliance testing for Crystal River Unit 4 was conducted on September 17, 2013 and on October 10, 2013. Compliance testing for Crystal River Unit 5 was conducted on September 18, 2013 and on October 11, 2013.

A total of 28 tests were performed on Unit 4 and a total of 23 tests were performed on Unit 5. These referenced test reports are included as an attachment to the application forms (Attachment CR-EU3-I1). In addition, a summary of the test results are presented in Tables 1 through 6 of the SAM Standard Operating protocol (SAM SOP) document (see Attachment CR-EU32-I1).

3.2 SAM Operating Protocol (SAM SOP)

In addition to the SAM performance testing, a revised SAM Standard Operating Protocol (SAM SOP) is required to be submitted to the Department after the test data are evaluated and implemented in the form of a correlation curve. The purpose of this SAM SOP is to outline how the AMM system will be operated at various load levels and operating conditions, based upon the results of the SAM performance tests.

It is DEF's interpretation that the SAM SOP serves as the basis for implementing the SAM "correlation curve/algorithm" that will be used to demonstrate ongoing compliance with the permitted SAM emission limits. This protocol document is intended to be separate from the permit, so that it can be modified in the future (as necessary) without a requirement to update the permit documents.

Although the permit language suggests that DEF was to *"conduct a minimum 1-hour test run to determine the SAM emissions for at least nine (9) different operating conditions",* that permit language dates back to the original air construction permit, and was developed based on potential unknown effects of various operational conditions associated with the originally designed ammonia based AMM system. During the initial commissioning of that system, the testing addressed various operational conditions. This information was used to develop the original Operating Protocol (for the ammonia system).

In general, DEF found that the only major effect on SAM emissions (at a consistent fuel sulfur level) was based on the sorbent injection rate. When DEF transitioned to the temporary hydrated lime system, the initial testing to develop the temporary hydrated lime AMM system operating protocol became more focused on interpreting the "nine different operating conditions" more as different injection rates/locations at different loads. That concept has carried forward to the recent testing of the permanent hydrated lime AMM system. Therefore, the testing that was conducted to support this permitting action was used as the basis for the new/revised operating protocol (the SAM SOP) developed to direct current operation of the AMM system.

3.3 SAM CAM Plan

The purpose of the performance test program was to document the impact of the AMM system injection rates on reducing SAM emissions and to develop a correlation curve between the injection rate, unit operating conditions/loads, and measured SAM emissions. Once the curve was developed (based upon the performance test data), it was programmed into the Distributed Control System (DCS) of each unit in order to continuously demonstrate compliance with the permitted SAM limit of 0.009 lb/mmBtu at any operating load level over each unit's range of operation (while the AMM system is operating).

The SAM emissions control equipment includes a hydrated lime based acid mist mitigation (AMM) system as the primary control. In addition, the original ammonia based AMM system remains available as a back-up control system. In order to control the amount of SAM that is exhausted through the stack, AMM systems have been installed that inject hydrated lime (primary system) or ammonia (back-up system) into the flue gas stream to reduce the concentration of SAM entering the flue gas desulfurization (FGD) system and out the stack.

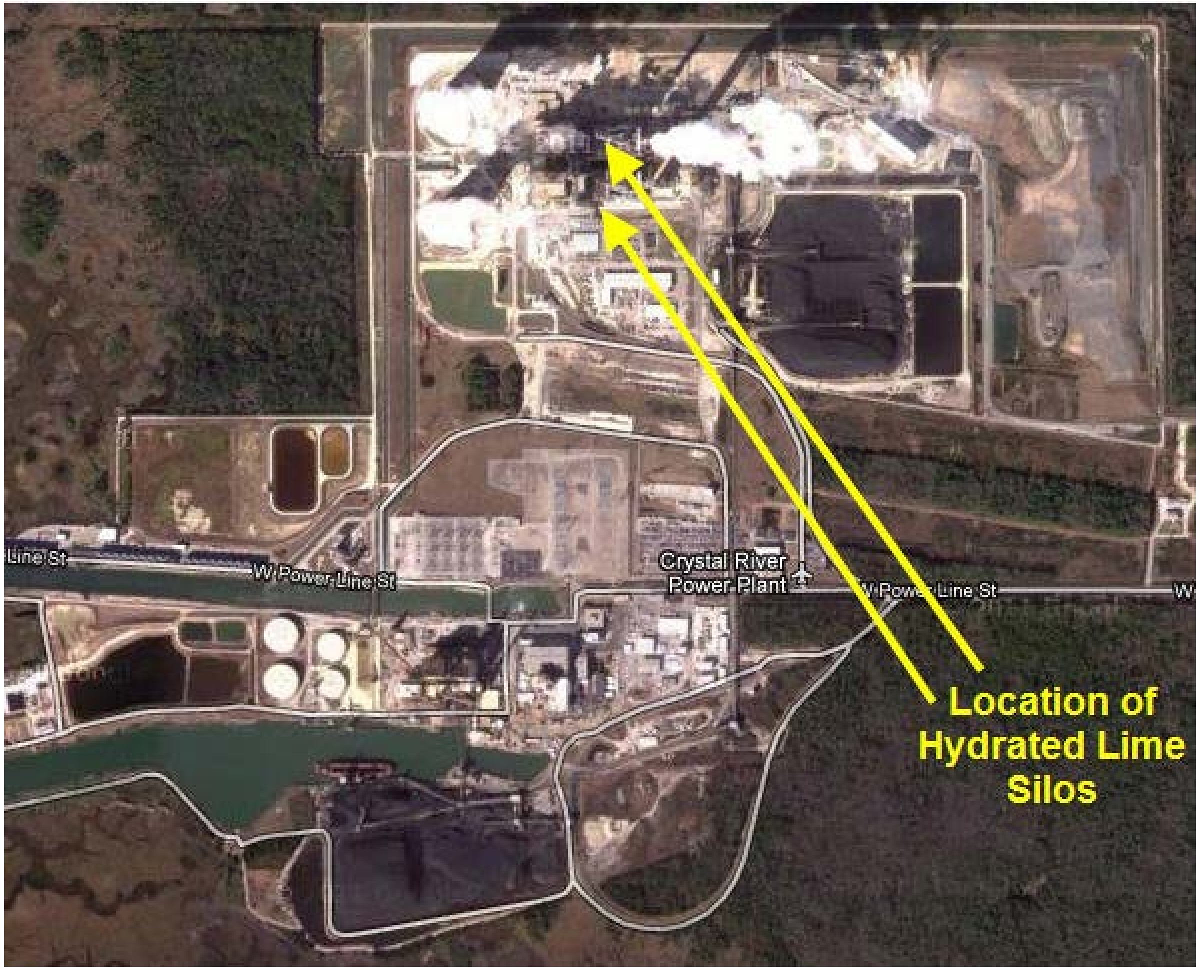
The purpose of this SAM CAM Plan (see Attachment CR-EU3-I2) is to outline how the AMM system (both the primary hydrated lime injection system and the backup ammonia injection system) will be operated at various load levels and operating conditions, based upon the results of the AMM performance test. The required level of AMM injection was determined during performance tests and following system tuning. Test data taken over three operating load levels (i.e., approximately 250 MW, 500 MW and full load) were used to interpolate an AMM injection curve over each unit's range of operation. The AMM system injection rate will be continuously monitored and recorded. The injection flow rate monitoring system will be properly calibrated, operated, and maintained in accordance with Rule 62-297.520, F.A.C.

It should be noted that compliance testing is required annually for SAM emissions for these units, as well as within 60 days of an increase of the fuel sulfur content of 0.5 percent or more. Such an increase in fuel sulfur content would also require an adjustment to the calibrated injection rates, as detailed in the attached SAM CAM Plan.

3.4 CO BACT Limit

Finally, Permit No. 0170004-030-AC (PSD-FL-383E), which was issued on June 30, 2011, revised the CO BACT limit for Units 4 and 5 from an interim standard of 0.17 pound per million British thermal units (lb/MMBtu) to a final standard of 0.10 lb/MMBtu. Apparently, this final standard was not incorporated by the Department into the current revised TV permit, which was issued on June 13, 2012. Therefore, this permit revision request is also included in this TV permit revision application package.

APPENDIX A
PROJECT FIGURES



CLIENT/PROJECT

Duke Energy Florida, Inc.

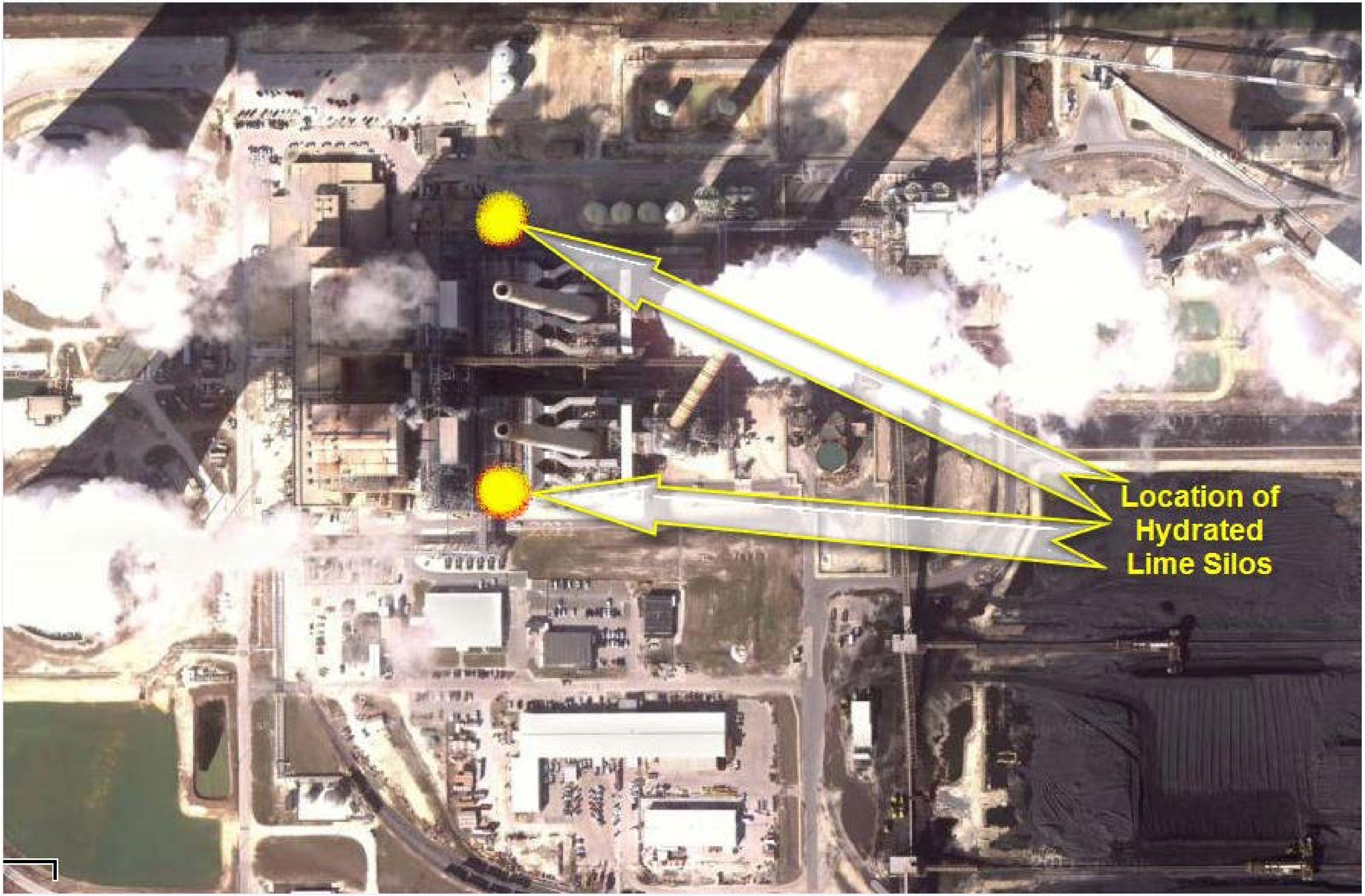
Golder Associates

TAMPA, FLORIDA

TITLE:

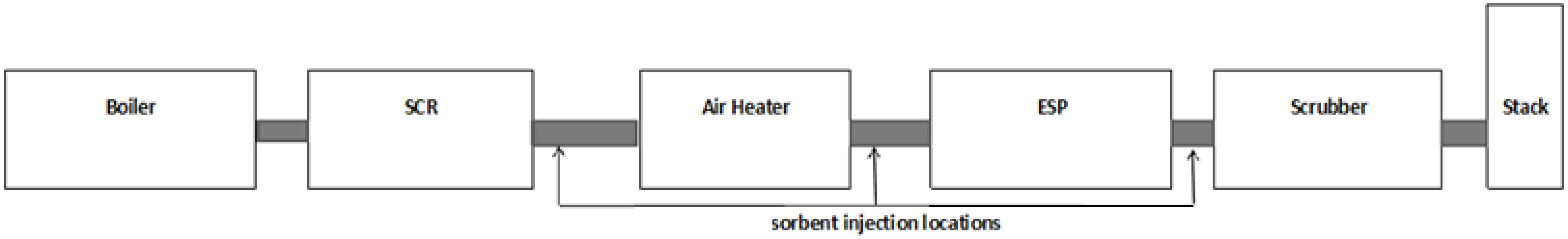
FIGURE 1 - SITE MAP

DRAWN BY: PP	REVIEWED BY: SO	DATE: 11/8/13	NOT TO SCALE	FILE NO.:	JOB NO.: 130-2150	CRYSTAL RIVER NORTH TITLE V REVISION PERMIT APPLICATION



CLIENT/PROJECT **Duke Energy Florida, Inc.**			Golder Associates TAMPA, FLORIDA			TITLE: **FIGURE 2 – PROJECT LOCATION**
	DRAWN BY: PP	REVIEWED BY: SO	DATE: 11/8/13	NOT TO SCALE	FILE NO.:	JOB NO.: 130-2150

CRYSTAL RIVER NORTH TITLE V REVISION
PERMIT APPLICATION



CLIENT/PROJECT

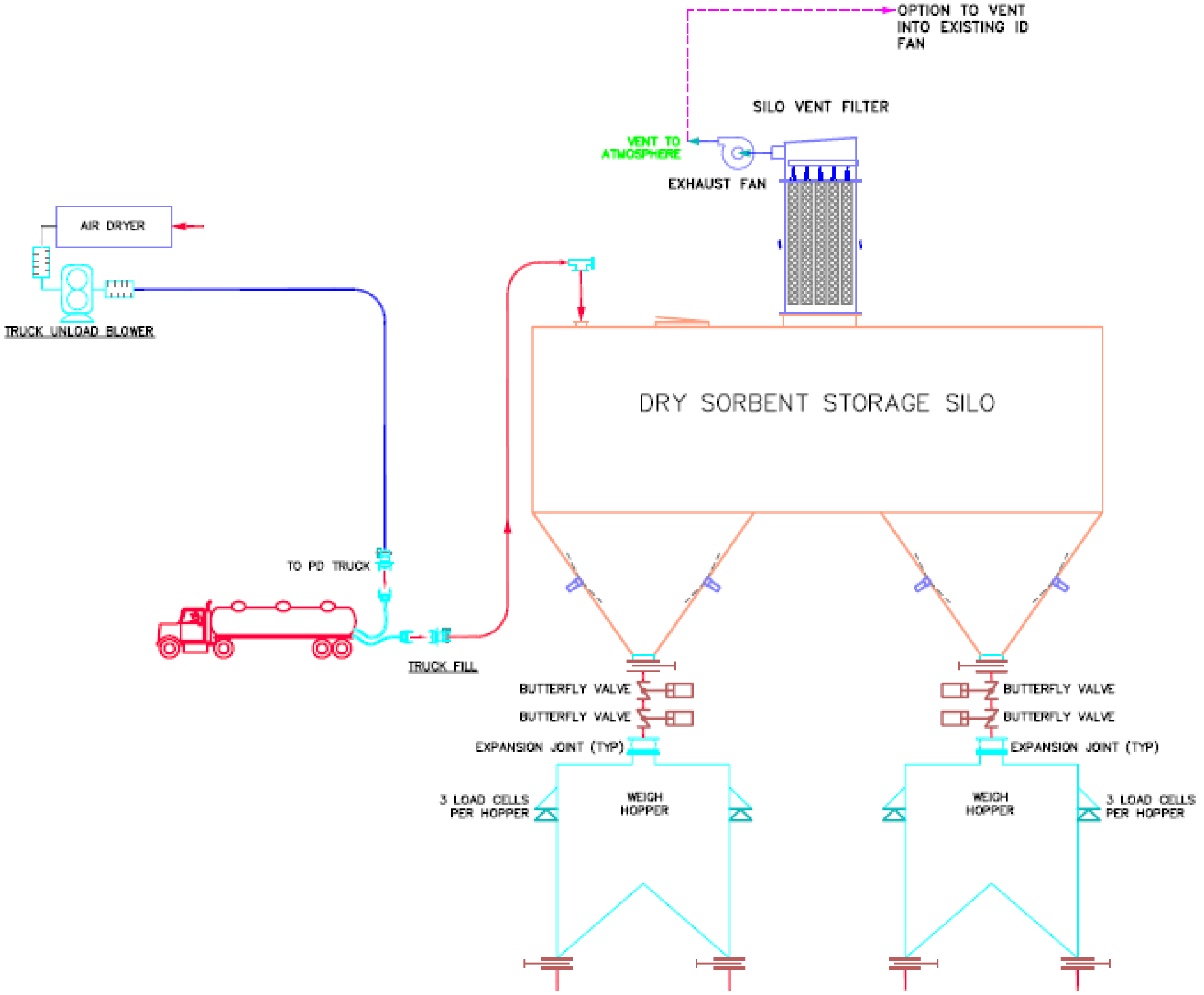
Duke Energy Florida, Inc.

TAMPA, FLORIDA

TITLE:

FIGURE 3 – SORBENT INJECTION LOCATION POINTS

DRAWN BY: PP	REVIEWED BY: SO	DATE: 11/8/13	NOT TO SCALE	FILE NO.:	JOB NO.: 130-2150	CRYSTAL RIVER NORTH TITLE V REVISION PERMIT APPLICATION



CLIENT/PROJECT

Duke Energy Florida, Inc.

TAMPA, FLORIDA

Golder Associates

TITLE:

FIGURE 4 –SORBENT INJECTION SYSTEM

DRAWN BY: PP

REVIEWED BY: SO

DATE: 11/8/13

NOT TO SCALE

FILE NO.:

JOB NO.: 130-2150

CRYSTAL RIVER NORTH TITLE V REVISION PERMIT APPLICATION

PART II
FDEP APPLICATION FOR AIR PERMIT

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **DUKE ENERGY FLORIDA, INC.**
2. Site Name: **CRYSTAL RIVER POWER PLANT**
3. Facility Identification Number: **0170004**
4. Facility Location...
   Street Address or Other Locator: **NORTH OF CRYSTAL RIVER, WEST OF U.S. 19**
   City: **CRYSTAL RIVER** County: **CITRUS** Zip Code: **34428**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name:
   JAMIE HUNTER, LEAD ENVIRONMENTAL SPECIALIST
2. Application Contact Mailing Address...
   Organization/Firm: **DUKE ENERGY FLORIDA, INC.**
   Street Address: **299 FIRST AVENUE, NORTH, FL 903**
   City: **ST. PETERSBURG** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers...
   Telephone: (**727**) **820-5764** ext. Fax: **727**) **820-5229**
4. Application Contact E-mail Address: **Jamie.Hunter@duke-energy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

☐ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☒ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Duke Energy Florida, Inc. is submitting this application for a Title V permit revision for the Crystal River Energy Complex (CREC) to request approval of operating changes following the construction of a permanent hydrated lime injection system (01740004-037-AC) for Crystal River Units 4 and 5.

Additionally, this application includes the revised CO BACT standard for Units 4 and 5 from an interim standard of 0.17 pound per million British thermal units (lb/MMBtu) to a final standard of 0.10 lb/MMBtu based on Permit No. 0170004-030-AC (PSD-FL-383E), which was issued on June 30, 2011.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
004	Unit 4 Fossil Fuel Steam Generator	AV02	NA
003	Unit 5 Fossil Fuel Steam Generator	AV02	NA
032	Hydrated Lime Storage and Transfer System	AV02	NA

Application Processing Fee

Check one: ☐ Attached - Amount:_________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :

2. Owner/Authorized Representative Mailing Address...
Organization/Firm:
Street Address:
City: State: Zip Code:

3. Owner/Authorized Representative Telephone Numbers...
Telephone: ( ) ext. Fax: ( )

4. Owner/Authorized Representative E-mail Address:

5. Owner/Authorized Representative Statement:

I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.

____________________________ ____________________
Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name: **Jay Chesser, Manager-Shift Operations-CR**

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

☒ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.

☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.

☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.

☐ The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...

Organization/Firm: **DUKE ENERGY FLORIDA, INC**
Street Address: **299 FIRST AVENUE, NORTH, CN77**
City: **ST PETERSBURG** State: **FLORIDA** Zip Code: **33701**

4. Application Responsible Official Telephone Numbers...

Telephone: **(352) 501-5230** ext. Fax: **(352) 501-5787**

5. Application Responsible Official E-mail Address: **Jay.Chesser@Duke-Energy.com**

6. Application Responsible Official Certification:

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

Signature

11/13/2013
Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott H. Osbourn**
   Registration Number: **57557**

2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.***
   Street Address: **5100 West Lemon St., Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**

3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. **53304** Fax: **(813) 287-1716**

4. Professional Engineer E-mail Address: **sosbourn@golder.com**

5. Professional Engineer Statement:

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

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

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

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

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

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

Signature

11/12/13
Date

(seal)

SCOTT H. OSBOURN
LICENSE No. 57557

*** Board of Professional Engineers Certificate of Authorization # 00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates...
   Zone **17** East (km) **334.3**
   North (km) **3204.5**
2. Facility Latitude/Longitude...
   Latitude (DD/MM/SS) **28/57/34**
   Longitude (DD/MM/SS) **82/42/01**
3. Governmental Facility Code: **0**
4. Facility Status Code: **A**
5. Facility Major Group SIC Code: **49**
6. Facility SIC(s): **4911**
7. Facility Comment :

Facility Contact

1. Facility Contact Name:
   JAMIE HUNTER, LEAD ENVIRONMENTAL SPECIALIST
2. Facility Contact Mailing Address...
   Organization/Firm: **DUKE ENERGY FLORIDA, INC**
   Street Address: **299 FIRST AVENUE, NORTH, FL 903**
   City: **ST PETERSBURG** State: **FLORIDA** Zip Code: **33701**
3. Facility Contact Telephone Numbers:
   Telephone: **(727) 820-5764** ext. Fax:
4. Facility Contact E-mail Address: **Jamie.Hunter@duke-energy.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official E-mail Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
$PM/PM_{10}/PM_{2.5}$	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
SO_2	**A**	**N**
NO_x	**A**	**N**
SAM	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**

2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**

3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**

Additional Requirements for Air Construction Permit Applications- NA

1. Area Map Showing Facility Location:
   ☐ Attached, Document ID:__________ ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):
   ☐ Attached, Document ID: _________
3. Rule Applicability Analysis:
   ☐ Attached, Document ID:___________
4. List of Exempt Emissions Units:
   ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification:
   ☐ Attached, Document ID:___________ ☐ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.):
   ☐ Attached, Document ID:___________ ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.):
   ☐ Attached, Document ID:___________ ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):
   ☐ Attached, Document ID:__________ ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):
   ☐ Attached, Document ID:__________ ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):
    ☐ Attached, Document ID:___________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications -NA

1. List of Exempt Emissions Units:
   ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities: (Required for initial/renewal applications only)
   ☐ Attached, Document ID:___________ ☒ Not Applicable (revision application)

2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought)
   ☐ Attached, Document ID:**CR-1**
   ☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)--**NA**
   ☐ Attached, Document ID:____
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:___________
   ☐ Equipment/Activities Onsite but Not Required to be Individually Listed
   ☒ Not Applicable

5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:___________ ☒ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☐ Attached, Document ID:_________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
☐ Attached, Document ID: ☒ Previously Submitted, Date: **May 20, 2009**
☐ Not Applicable (not an Acid Rain source)

Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
☐ Attached, Document ID:____________ ☒ Previously Submitted, Date: **May 20, 2009**
☐ Not Applicable

New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:____________
☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
☐ Attached, Document ID: ☒ Previously Submitted, Date: **May 20, 2009**
☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

Fossil Fuel Steam Generator-4 (Phase II Acid Rain Unit)

3. Emissions Unit Identification Number: **004**

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **October 2012**	6. Initial Startup Date: **12/1/1982**	7. Emissions Unit Major Group SIC Code: **49**

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **760** MW

11. Emissions Unit Comment:

Pulverized Coal Dry Bottom Boiler, Wall-Fired.

Emissions Unit Control Equipment/Method: Control **1** of **6**

1. Control Equipment/Method Description:
   Alkali Injection

2. Control Device or Method Code: **032**

Emissions Unit Control Equipment/Method: Control **2** of **6**

1. Control Equipment/Method Description:
   Flue Gas Desulfurization (FGD)

2. Control Device or Method Code:**039**

Emissions Unit Control Equipment/Method: Control **3** of **6**

1. Control Equipment/Method Description:
   Electrostatic Precipitator (ESP)- High Efficiency (95.0 – 99.9%)

2. Control Device or Method Code:**010**

Emissions Unit Control Equipment/Method: Control **4** of **6**

1. Control Equipment/Method Description:
   Low NOx Burners (LNB)

2. Control Device or Method Code:**205**

Emissions Unit Control Equipment/Method: Control **5** of **6**

1. Control Equipment/Method Description:
   Selective Catalytic Reduction (SCR)

2. Control Device or Method Code:**139**

Emissions Unit Control Equipment/Method: Control **6** of **6**

1. Control Equipment/Method Description:
   Wet Limestone Injection

2. Control Device or Method Code:**042**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:

2. Maximum Production Rate:

3. Maximum Heat Input Rate: **7,200 million Btu/hr**

4. Maximum Incineration Rate: pounds/hr
tons/day

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

6. Operating Capacity/Schedule Comment:

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average. The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight). Compliance is demonstrated by collecting the fuel feed rate and fuel heating values as monitored by the existing operating data monitoring system.

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **EU 004**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **550 feet**	7. Exit Diameter: **30.5 feet**
8. Exit Temperature: **130**°F[a]	9. Actual Volumetric Flow Rate: **2,205,195** acfm[a]	10. Water Vapor: %[a]
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **334.7768** North (km): **3205.39342**	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack parameters provided for 100% load and maximum heat input of 7,200 MMBtu/hr.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **4**

1. Segment Description (Process/Fuel Type): **Bituminous coal & bituminous coal briquette mixture**		
2. Source Classification Code (SCC): **10100202**		3. SCC Units: **Tons Bituminous Coal Burned**
4. Maximum Hourly Rate: **316.5**	5. Maximum Annual Rate: **2,618,373.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **5.5 lb/MMBtu SO_2**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **22.75**
10. Segment Comment: **Based on bituminous coal and coal briquette high heating value (HHV) of 11,375 Btu/lb.** **The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).** **Maximum hourly rate = 7,200 MMBtu/hr /11,375 Btu/lb *1ton/2000 lb = 316.5 tons/hr** **The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.** **Maximum annual rate = 6,800 MMBtu/hr /11,375 Btu/lb *1ton/2000 lb *8,760 hr/yr = 2618373.6 tons/yr**		

Segment Description and Rate: Segment **2** of **4**

1. Segment Description (Process/Fuel Type): **Distillate fuel oil used as an igniter fuel**		
2. Source Classification Code (SCC): **10100501**		3. SCC Units: **1000 Gallons Distillate Oil (No. 1 & 2) Burned**
4. Maximum Hourly Rate: **48.297**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.73**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Distillate fuel oil used as an igniter fuel for startup and low-load flame stabilization**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **3** of **4**

1. Segment Description (Process/Fuel Type): **Natural gas as startup and low-load flame stabilization fuel**		
2. Source Classification Code (SCC): **10100601**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Natural gas as startup and low-load flame stabilization fuel**		

Segment Description and Rate: Segment **4** of **4**

1. Segment Description (Process/Fuel Type): **On specification used oil**		
2. Source Classification Code (SCC): **10101302**	3. SCC Units: **1000 Gallons Waste Oil Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Used oil specification: Arsenic 5 PPM, Cadmium 2 PPM, Chromium 10 PPM, Lead 100 PPM, Total Halogens 1000 PPM, PCB 50 PPM, 10 million gal/12 month limit for all 4 steam generating units (FFSG 1, 2, 4, & 5)**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
Total PM/PM$_{10}$	**010**	**-----**	**EL**
CO	**-----**	**-----**	**EL**
VOC	**-----**	**-----**	**EL**
SO$_2$	**039**	**-----**	**EL**
SAM	**042**	**032**	**EL**
NO$_x$	**139**	**205**	**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Total PM/PM_{10}**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **216** lb/hour **759.5** tons/year

4. Synthetically Limited? ☐Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.03 lb/MMBtu**

Reference: **BACT**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.03 lb/MMBtu = 216 lb/hr (based on a 3-run test average conducted at permitted capacity

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800MMBtu/hr*0.03 lb/MMBtu * 8760 hrs/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 759.5 TPY

PM_{10} is assumed to be equal to PM.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.03 lb/MMBtu heat input**	4. Equivalent Allowable Emissions: **216** lb/hour **759.5** tons/year
5. Method of Compliance: **EPA Method 5 or 5B; Annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emission based on a 3 run test average determined by EPA Method 5 or 5B [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383]**	

Allowable Emissions Allowable Emissions __of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **720** lb/hour **2,531.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.10 lb/MMBtu** Reference: **BACT (Permit No. 0170004-030-AC)**	7. Emissions Method Code: **1A**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 0.10 lb/MMBtu * 7,200 MMBtu/hr = 720 lb/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800 MMBtu/hr *0.10 lb/MMBtu * 8760 hr/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 2,531.6 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.10 lb/MMBtu**	4. Equivalent Allowable Emissions: **720** lb/hour **2,531.6** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions (lb/MMBtu) based on a 30 day rolling average excluding startup, shutdown, malfunctions. Emissions (lb/hr) based on a 30-day rolling average for all periods of operation including startup, shutdown, and malfunctions. [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383].**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **28.8** lb/hour **101.2** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.004 lb/MMBtu**

Reference: **Vendor Specification/Process Knowledge**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).

lb/hr = 0.004 lb/MMBtu * 7,200 MMBtu/hr = 28.8 lb/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.

TPY = 6,800 MMBtu/hr *0.004 lb/MMBtu * 8760 hr/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 101.2 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.004 lb/MMBtu**	4. Equivalent Allowable Emissions: **28.8** lb/hour **101.2** tons/year
5. Method of Compliance: **EPA Method 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emission based on a 3 run test average determined by EPA Method 25A [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383]**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **SO_2**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **1,944** lb/hour **6,835.4** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.27 lb/MMBtu**

Reference: **Based on modeled impacts.**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.27 lb/MMBtu = 1,944 lb/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800 MMBTu/hr* 0.27 lb/MMBtu* 8760 hr/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 6,835.4 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.27 lb/MMBtu heat input**	4. Equivalent Allowable Emissions: **1,944** lb/hour **6,835.4** tons/year
5. Method of Compliance: **As determined by CEMS data, SO_2 emissions shall not exceed 0.27 lb/MMBtu based on a 30-day rolling average for all periods of operation including startup, shutdown, and malfunction. As determined by CEMS data, SO2 emissions shall not exceed 1,944 lb/hr/unit based on a 24-hour block average excluding startup, shutdown, and malfunction of the FGD system.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **%**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SAM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **64.8** lb/hour **227.9** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.009 lb/MMbtu**

Reference: **BACT/Vendor Specification/Process Knowledge**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.009 lb/MMBtu = 64.8 lb/hr.

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800*0.009 lb/MMBtu * 8760 hrs/yr * 1 ton/2000 lb * 0.85 Capacity Factor =227.9 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.009 lb/MMBtu**	4. Equivalent Allowable Emissions: **64.8** lb/hour **227.9** tons/year
5. Method of Compliance: **SAM CAM Plan (Attachment CR-EU3-I2) used for continuous compliance.** **Hydrated lime injection system as the primary means of SAM emissions control, with the previously used ammonia injection system retained as the backup system.**	
6. Allowable Emissions Comment (Description of Operating Method): **Compliance based on 3 run test average determined by EPA Method 8 or 8a except during periods of maintenance and repair as authorized in permit No. 0170004-023-AC. [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383]**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **3,384** lb/hour **2,085** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.47 lb/MMBtu**
Reference: **Acid Rain**

7. Emissions Method Code: **0**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.47 lb/MMBtu = 3,384 lb/hr.

As determined by CEMS data, NOx emissions not to exceed 2,085 TPY based on a 12-month rolling average for all periods of operation including startup, shutdown, and malfunction.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.47 lb/MMBtu heat input**	4. Equivalent Allowable Emissions: **3,384** lb/hour tons/year

5. Method of Compliance:
EPA Method 7E: Continuous Emission Monitoring (CEM), annual average.

6. Allowable Emissions Comment (Description of Operating Method):
Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year

5. Method of Compliance:

6. Allowable Emissions Comment (Description of Operating Method):

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year

5. Method of Compliance:

6. Allowable Emissions Comment (Description of Operating Method):

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: **VE10 – Visible Emissions**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other

3. Allowable Opacity:
Normal Conditions: **10** % Exceptional Conditions: **20** %
Maximum Period of Excess Opacity Allowed: **6** min/hour

4. Method of Compliance:
Determined by EPA Method 9

5. Visible Emissions Comment:

Determined by EPA Method 9 [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383].

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **VE – Visible Emissions**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other

3. Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
COMS in ductwork.

5. Visible Emissions Comment:
The COM measurements also serve as the basis for the PM CAM Plan.

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **6**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **THERMO (TEI)** Model Number: **42 I**	Serial Number: **CM09040029**
5. Installation Date: **MAY 13, 2010**	6. Performance Specification Test Date: **JULY 12, 2010**
7. Continuous Monitor Comment: **40 CFR 75, NOX**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **THERMO (TEI)** Model Number: **43I**	Serial Number: **CM09040035**
5. Installation Date: **MAY 13, 2010**	6. Performance Specification Test Date: **JULY 12, 2010**
7. Continuous Monitor Comment: **40 CFR 75, SO_2**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **3** of **6**

1. Parameter Code: **VE – Visible Emissions (opacity)**	2. Pollutant(s): **PM**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Teledyne** Model Number: **Lighthawk 560**	Serial Number: **5601946, 5601497, 5601948, 5601949**
5. Installation Date: **May 13, 2010**	6. Performance Specification Test Date: **June 9, 2010**
7. Continuous Monitor Comment: **40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: **CO_2 – Carbon Dioxide**	2. Pollutant(s): **CO_2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Siemens** Model Number: **Ultramat 6**	Serial Number: **F-NR.N1-X2-795**
5. Installation Date: **May 13, 2010**	6. Performance Specification Test Date: **July 12, 2010**
7. Continuous Monitor Comment: **40 CFR 75**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: **FLOW – Volumetric Flow Rate**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Teledyne** Model Number: **Ultraflow 150**	Serial Number: **1501014**
5. Installation Date: **May 13, 2010**	6. Performance Specification Test Date: **July 12, 2010**
7. Continuous Monitor Comment: **40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: **CO – Carbon Monoxide**	2. Pollutant(s): **CO**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **THERMO (TEI)** Model Number: **48I**	Serial Number:
5. Installation Date: **May 13, 2010**	6. Performance Specification Test Date: **July 12, 2010**
7. Continuous Monitor Comment: **40 CFR 60**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___ ☒ Previously Submitted, Date **May 20, 2009**

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___ ☒ Previously Submitted, Date **May 20, 2009**

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:___ ☒ Previously Submitted, Date **June 18, 2012 and November 9, 2010**

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date **May 20, 2009**
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date **May 20, 2009**
   ☐ Not Applicable (construction application)

6. Compliance Demonstration Reports/Records:

☒ Attached, Document ID: **CR-EU3-I1**

Test Date(s)/Pollutant(s) Tested: **October 9, 2013/Sulfuric Acid Mist**

☒ Previously Submitted, Date: ______________

1. EPA Method 5 or 5A stack test results for particulate matter

Test Date(s)/Pollutant(s) Tested: 2/21/09, 8/4/2010 and 8/5/2010

2. EPA Method 10 stack test results for carbon monoxide

Test Date(s)/Pollutant(s) Tested: 2/6/2009 – 2/12/2009

3. EPA Method 18, 25, or 25A stack test results for volatile organic compounds

Test Date(s)/Pollutant(s) Tested: 3/3/2009

4. EPA Method 6C stack test results

Test Date(s)/Pollutant(s) Tested: August 2010

5. EPA Method 7E stack test results

Test Date(s)/Pollutant(s) Tested: August 2010

6. EPA Method 9 stack test results

Test Date(s)/Pollutant(s) Tested: 8/4/2010 and 8/5/2010

☐ To be Submitted, Date (if known):____________________

Test Date(s)/Pollutant(s) Tested: ____

☐ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:

☐ Attached, Document ID: _________________ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):
   ☐ Attached, Document ID: ___________ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):
   ☐ Attached, Document ID: ___________ ☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: ___________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements:
   ☒ Attached, Document ID: **CR-1**
2. Compliance Assurance Monitoring:
   ☒ Attached, Document ID: **CR-EU3-I2**[a] ☐ Not Applicable
3. Alternative Methods of Operation:
   ☐ Attached, Document ID: ___________ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading):
   ☐ Attached, Document ID: ___________ ☒ Not Applicable

Additional Requirements Comment

[a]**SAM CAM Plan attached**

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an “unregulated emissions unit” does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

Fossil Fuel Steam Generator-5 (Phase Ii Acid Rain Unit)

3. Emissions Unit Identification Number: **003**

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **October 2012**	6. Initial Startup Date: **12/1/1984**	7. Emissions Unit Major Group SIC Code: **49**

8. Federal Program Applicability: (Check all that apply)

☒ Acid Rain Unit

☒ CAIR Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **760 MW**

11. Emissions Unit Comment:

Pulverized Coal Dry Bottom Boiler, Wall-Fired.

EMISSIONS UNIT INFORMATION

Section [2] of [3]

EU 003 - Unit 5 Fossil Fuel Steam Generator

Emissions Unit Control Equipment/Method: Control **1** of **6**

1. Control Equipment/Method Description:
   Alkali Injection
2. Control Device or Method Code: **032**

Emissions Unit Control Equipment/Method: Control **2** of **6**

1. Control Equipment/Method Description:
   Flue Gas Desulfurization (FGD)
2. Control Device or Method Code:**039**

Emissions Unit Control Equipment/Method: Control **3** of **6**

1. Control Equipment/Method Description:
   Electrostatic Precipitator (ESP)- High Efficiency (95.0 – 99.9%)
2. Control Device or Method Code:**010**

Emissions Unit Control Equipment/Method: Control **4** of **6**

1. Control Equipment/Method Description:
   Low NOx Burners (LNB)
2. Control Device or Method Code:**205**

Emissions Unit Control Equipment/Method: Control **5** of **6**

1. Control Equipment/Method Description:
   Selective Catalytic Reduction (SCR)
2. Control Device or Method Code:**139**

Emissions Unit Control Equipment/Method: Control **6** of **6**

1. Control Equipment/Method Description:
   Wet Limestone Injection
2. Control Device or Method Code:**042**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:

2. Maximum Production Rate:

3. Maximum Heat Input Rate: **7,200 million Btu/hr**

4. Maximum Incineration Rate: pounds/hr
tons/day

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

6. Operating Capacity/Schedule Comment:

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average. The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight). Compliance is demonstrated by collecting the fuel feed rate and fuel heating values as monitored by the existing operating data monitoring system.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **EU003**

2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

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

5. Discharge Type Code: **V**

6. Stack Height: **550** feet

7. Exit Diameter: **30.5** feet

8. Exit Temperature: **130**°F[a]

9. Actual Volumetric Flow Rate: **2,205,195** acfm[a]

10. Water Vapor: %[a]

11. Maximum Dry Standard Flow Rate: Dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates...
Zone: **17** East (km): **334.7768**
North (km): **3205.39342**

14. Emission Point Latitude/Longitude…
Latitude (DD/MM/SS)
Longitude (DD/MM/SS)

15. Emission Point Comment:

Stack parameters provided for 100% load and maximum heat input of 7,200 MMBtu/hr.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **4**

1. Segment Description (Process/Fuel Type):

Bituminous coal & bituminous coal briquette mixture

2. Source Classification Code (SCC): **10100202**	3. SCC Units: **Tons Bituminous Coal Burned**	
4. Maximum Hourly Rate: **316.5**	5. Maximum Annual Rate: **2,618,373.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **5.5 lb/MMBtu SO_2**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **22.75**

10. Segment Comment:

Based on bituminous coal and coal briquette high heating value (HHV) of 11,375 Btu/lb.

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
Maximum hourly rate = 7,200 MMBtu/hr /11,375 Btu/lb *1ton/2000 lb = 316.5 tons/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
Maximum annual rate = 6,800 MMBtu/hr /11,375 Btu/lb *1ton/2000 lb *8,760 hr/yr = 2618373.6 tons/yr

Segment Description and Rate: Segment **2** of **4**

1. Segment Description (Process/Fuel Type):

Distillate fuel oil used as an igniter fuel

2. Source Classification Code (SCC): **10100501**	3. SCC Units: **1000 Gallons Distillate Oil (No. 1 & 2) Burned**	
4. Maximum Hourly Rate: **48.297**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.73**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138**

10. Segment Comment:

Distillate fuel oil used as an igniter fuel for startup and low-load flame stabilization

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **3** of **4**

1. Segment Description (Process/Fuel Type): **Natural gas as startup and low-load flame stabilization fuel**			
2. Source Classification Code (SCC): **10100601**		3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment: **Natural gas as startup and low-load flame stabilization fuel**			

Segment Description and Rate: Segment **4** of **4**

1. Segment Description (Process/Fuel Type): **On specification used oil**			
2. Source Classification Code (SCC): **10101302**		3. SCC Units: **1000 Gallons Waste Oil Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment: **Used oil specification: Arsenic 5 PPM, Cadmium 2 PPM, Chromium 10 PPM, Lead 100 PPM, Total Halogens 1000 PPM, PCB 50 PPM, 10 million gal/12 month limit for all 4 steam generating units (FFSG 1, 2, 4, & 5)**			

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
Total PM/PM_{10}	**010**	**-----**	**EL**
CO	**-----**	**-----**	**EL**
VOC	**-----**	**-----**	**EL**
SO_2	**039**	**-----**	**EL**
SAM	**042**	**032**	**EL**
NO_x	**139**	**205**	**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Total PM/PM_{10}**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **216** lb/hour **759.5** tons/year

4. Synthetically Limited? ☐Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: **0.03 lb/MMBtu**
Reference: **BACT**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required):
tons/year

8.b. Baseline 24-month Period:
From: To:

9.a. Projected Actual Emissions (if required):
tons/year

9.b. Projected Monitoring Period:
☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.03 lb/MMBtu = 216 lb/hr (based on a 3-run test average conducted at permitted capacity

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800MMBtu/hr*0.03 lb/MMBtu * 8760 hrs/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 759.5 TPY

PM_{10} is assumed to be equal to PM.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.03 lb/MMBtu heat input**
4. Equivalent Allowable Emissions: **216** lb/hour **759.5** tons/year
5. Method of Compliance: **EPA Method 5 or 5B; Annually.**
6. Allowable Emissions Comment (Description of Operating Method): **Emission based on a 3 run test average determined by EPA Method 5 or 5B [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383]**

Allowable Emissions Allowable Emissions __of ___

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:
6. Allowable Emissions Comment (Description of Operating Method):

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:
6. Allowable Emissions Comment (Description of Operating Method):

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **680** lb/hour **2,531.6** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: **0.10 lb/MMBtu**

Reference: **BACT (Permit No. 0170004-030-AC)**

7. Emissions Method Code: **1A**

8.a. Baseline Actual Emissions (if required):
tons/year

8.b. Baseline 24-month Period:
From: To:

9.a. Projected Actual Emissions (if required):
tons/year

9.b. Projected Monitoring Period:
☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 0.10 lb/MMBtu * 6,800 MMBtu/hr = 680 lb/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800 MMBtu/hr *0.10 lb/MMBtu * 8760 hr/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 2,531.6 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.10 lb/MMBtu**	4. Equivalent Allowable Emissions: **720** lb/hour **2,531.6** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions (lb/MMBtu) based on a 30 day rolling average excluding startup, shutdown, malfunctions. Emissions (lb/hr) based on a 30-day rolling average for all periods of operation including startup, shutdown, and malfunctions. [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383].**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **28.8** lb/hour **101.2** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.004 lb/MMBtu**

Reference: **Vendor Specification/Process Knowledge**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).

lb/hr = 0.004 lb/MMBtu * 7,200 MMBtu/hr = 28.8 lb/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.

TPY = 6,800 MMBtu/hr *0.004 lb/MMBtu * 8760 hr/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 101.2 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.004 lb/MMBtu**	4. Equivalent Allowable Emissions: **28.8** lb/hour **101.2** tons/year
5. Method of Compliance: **EPA Method 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Emission based on a 3 run test average determined by EPA Method 25A [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383]**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO_2**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **1,944** lb/hour **6,835.4** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.27 lb/MMBtu**
Reference: **Based on modeled impacts.**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.27 lb/MMBtu = 1,944 lb/hr

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800 MMBTu/hr* 0.27 lb/MMBtu* 8760 hr/yr * 1 ton/2000 lb * 0.85 Capacity Factor = 6,835.4

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.27 lb/MMBtu heat input**	4. Equivalent Allowable Emissions: **1,944** lb/hour **6,835.4** tons/year
5. Method of Compliance: **As determined by CEMS data, SO_2 emissions shall not exceed 0.27 lb/MMBtu based on a 30-day rolling average for all periods of operation including startup, shutdown, and malfunction. As determined by CEMS data, SO2 emissions shall not exceed 1,944 lb/hr/unit based on a 24-hour block average excluding startup, shutdown, and malfunction of the FGD system.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **%**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SAM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **64.8** lb/hour **227.9** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.009 lb/MMbtu**
Reference: **BACT/Vendor Specification/Process Knowledge**

7. Emissions Method Code: **2**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.009 lb/MMBtu = 64.8 lb/hr.

The maximum annual average heat input is 6,800 MMBtu/hr, based on a 30 day rolling average.
TPY = 6,800*0.009 lb/MMBtu * 8760 hrs/yr * 1 ton/2000 lb * 0.85 Capacity Factor =227.9 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.009 lb/MMBtu**	4. Equivalent Allowable Emissions: **64.8** lb/hour **227.9** tons/year
5. Method of Compliance: **SAM CAM Plan (Attachment CR-EU3-I2) used for continuous compliance.** **Hydrated lime injection system as the primary means of SAM emissions control, with the previously used ammonia injection system retained as the backup system.**	
6. Allowable Emissions Comment (Description of Operating Method): **Compliance based on 3 run test average determined by EPA Method 8 or 8a except during periods of maintenance and repair as authorized in permit No. 0170004-023-AC. [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383]**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **NOx**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **3,384** lb/hour **2,085** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.47 lb/MMBtu**
Reference: **Acid Rain**

7. Emissions Method Code: **0**

8.a. Baseline Actual Emissions (if required): tons/year

8.b. Baseline 24-month Period: From: To:

9.a. Projected Actual Emissions (if required): tons/year

9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

The maximum heat input is 7,200 MMBtu/hr, based on a 24-hour block average (midnight to midnight).
lb/hr = 7,200 MMBtu/hr * 0.47 lb/MMBtu = 3,384 lb/hr.

As determined by CEMS data, NOx emissions not to exceed 2,085 TPY based on a 12-month rolling average for all periods of operation including startup, shutdown, and malfunction.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.47 lb/MMBtu heat input**	4. Equivalent Allowable Emissions: **3,384** lb/hour tons/year
5. Method of Compliance: **EPA Method 7E: Continuous Emission Monitoring (CEM), annual average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: **VE10 – Visible Emissions**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other

3. Allowable Opacity:
Normal Conditions: **10** % Exceptional Conditions: **20** %
Maximum Period of Excess Opacity Allowed: **6** min/hour

4. Method of Compliance:
Determined by EPA Method 9

5. Visible Emissions Comment:

Determined by EPA Method 9 [Permit Nos. 0170004-023-AC; PSD-FL-383C, 0170004-022-AC; PSD-FL-383B, 0170004-019-AC; PSD-FL-383A, and 0170004-016-AC; PSD-FL-383].

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **VE – Visible Emissions**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other

3. Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
COMS in ductwork.

5. Visible Emissions Comment:
The COM measurements also serve as the basis for the PM CAM Plan.

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **THERMO (TEI)** Model Number: **42 I**	Serial Number: **CM08450036**
5. Installation Date: **November 24, 2009**	6. Performance Specification Test Date: **January 29, 2010**
7. Continuous Monitor Comment: **40 CFR 75, NOX**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **THERMO (TEI)** Model Number: **43I**	Serial Number: **CM08080023**
5. Installation Date: **November 24, 2009**	6. Performance Specification Test Date: **January 29, 2010**
7. Continuous Monitor Comment: **40 CFR 75, SO_2**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **3** of **6**

1. Parameter Code: **VE – Visible Emissions (opacity)**	2. Pollutant(s): **PM**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Teledyne** Model Number: **Lighthawk 560**	Serial Number: **5601893, 5601894, 5601895, 5601896**
5. Installation Date: **November 24, 2009**	6. Performance Specification Test Date: **December 17, 2009**
7. Continuous Monitor Comment: **40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: **CO_2 – Carbon Dioxide**	2. Pollutant(s): **CO_2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Siemens** Model Number: **Ultramat 6**	Serial Number: **F-NR.NI-WD-270**
5. Installation Date: **November 24, 2009**	6. Performance Specification Test Date: **January 29, 2010**
7. Continuous Monitor Comment: **40 CFR 75**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: **FLOW – Volumetric Flow Rate**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Teledyne** Model Number: **Ultraflow 150** Serial Number: **1500996**	
5. Installation Date: **November 24, 2009**	6. Performance Specification Test Date: **January 29, 2010**
7. Continuous Monitor Comment: **40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: **CO – Carbon Monoxide**	2. Pollutant(s): **CO**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **THERMO (TEI)** Model Number: **48I** Serial Number: **CM09040057**	
5. Installation Date: **November 24, 2009**	6. Performance Specification Test Date: **January 29, 2010**
7. Continuous Monitor Comment: **40 CFR 60**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___ ☒ Previously Submitted, Date **May 20, 2009**

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: ___ ☐ Previously Submitted, Date **May 20, 2009**

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID:___ ☒ Previously Submitted, Date **June 18, 2012 and November 9, 2010**

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date **May 20, 2009**
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:__ ☐ Previously Submitted, Date **May 20,2009**
   ☐ Not Applicable (construction application)

6. Compliance Demonstration Reports/Records:

☒ Attached, Document ID: **CR-EU3-I1**

Test Date(s)/Pollutant(s) Tested: **October 9, 2013/Sulfuric Acid Mist**

☒ Previously Submitted, Date: _____________

1. EPA Method 5 or 5A stack test results for particulate matter

Test Date(s)/Pollutant(s) Tested: 7/22/2009

2. EPA Method 10 stack test results for carbon monoxide

Test Date(s)/Pollutant(s) Tested: 7/22/2009

3. EPA Method 18, 25, or 25A stack test results for volatile organic compounds

Test Date(s)/Pollutant(s) Tested: 7/22/2009

4. EPA Method 6C stack test results

Test Date(s)/Pollutant(s) Tested: March 1, 2010

5. EPA Method 7E stack test results

Test Date(s)/Pollutant(s) Tested: 7/22/2009, March 1, 2010

6. EPA Method 9 stack test results

Test Date(s)/Pollutant(s) Tested: 7/22/2009, 5/21/2010, 5/25/2010

Test Date(s)/Pollutant(s) Tested: ____

☐ To be Submitted, Date (if known):___________________

Test Date(s)/Pollutant(s) Tested: ____

☐ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:

☐ Attached, Document ID: ________________ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):
   ☐ Attached, Document ID: ___________ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):
   ☐ Attached, Document ID: ___________ ☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: ___________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements:
   ☒ Attached, Document ID: **CR-1**
2. Compliance Assurance Monitoring:
   ☒ Attached, Document ID: **CR-EU3-I2**[a]_ ☐ Not Applicable
3. Alternative Methods of Operation:
   ☐ Attached, Document ID: ___________ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading):
   ☐ Attached, Document ID: ___________ ☒ Not Applicable

Additional Requirements Comment

[a]SAM CAM Plan attached.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   The hydrated lime storage system for each unit will consist of the following primary components: a hydrated lime storage silo, which is controlled by a dust collector fabric filter (silo vent filter), rotary valves and blowers for pneumatic delivery of the hydrated lime and hydrated lime injection lances. There is one emission point for the system serving Unit 4 and one emissions point for the system serving Unit 5.

3. Emissions Unit Identification Number: **032**

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **October 2012**	6. Initial Startup Date: **July 2013**	7. Emissions Unit Major Group SIC Code: **49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
Hydrated lime injection system for SAM reduction for currently authorized coal fuel blends

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **EP-1 and EP-2: Dust collector fabric filter (silo vent filter)**
2. Control Device or Method Code: **018**

Emissions Unit Control Equipment/Method: Control __ of __

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

Emissions Unit Control Equipment/Method: Control __ of __

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

Emissions Unit Control Equipment/Method: Control __ of __

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

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **2,000 scfm during loading operations**

2. Maximum Production Rate:

3. Maximum Heat Input Rate: million Btu/hr[a]

4. Maximum Incineration Rate: pounds/hr
tons/day

5. Requested Maximum Operating Schedule:
6 hours/day **7** days/week
52 weeks/year **2,184** hours/year

6. Operating Capacity/Schedule Comment:

The silo dust collector vent will have a flow rate of approximately 2,000 scfm during the loading operations, which are estimated to occur for 6 hours per day.

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:	2. Emission Point Type Code: **3**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:
One silo vent for hydrated lime storage and transfer system serving EU004.
One silo vent for hydrated lime storage and transfer system serving EU003.

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

5. Discharge Type Code: **P**	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: 77°F[a]	9. Actual Volumetric Flow Rate: acfm[a]	10. Water Vapor: %[a]

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: **Various** feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

To the extent practicable, the hydrated lime handling and storage operations shall be enclosed and confined to prevent fugitive dust emissions

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Hydrated Lime Storage and Transfer Systems for Unit 4 and Unit 5**		
2. Source Classification Code (SCC): **30501615**	3. SCC Units: **Million Cubic Feet Processed**	
4. Maximum Hourly Rate: **0.24**	5. Maximum Annual Rate: **525.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Max Hourly Rate: 2,000 scfm x 60 min/hr / 10^6 x 2 units (Unit 4 &5)= 0.24 million cubic feet** **Max Annual Rate: 2,000 scfm x 60 min/hr / 10^6 x 6 hr/day x 365 day/yr x 2 units (Unit 4 &5)= 525.6 million cubic feet**		

Segment Description and Rate: Segment _ of _

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM/PM_{10}	**018**	**-----**	**WP**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **PM/PM_{10}**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **0.51** lb/hour **0.56** tons/year

4. Synthetically Limited? ☐Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: **0.015 grains/dscf**
Reference: **Manufacturer specification**

7. Emissions Method Code:
3

8.a. Baseline Actual Emissions (if required):
tons/year

8.b. Baseline 24-month Period:
From: To:

9.a. Projected Actual Emissions (if required):
tons/year

9.b. Projected Monitoring Period:
☐ 5 years ☐ 10 years

10. Calculation of Emissions:

2,000 scfm x 60 min/hr x 0.015 grains/dscf x 1.4286E-4 lbs/grain x 2 units (Unit 4 &5)= 0.51 lbs/hr

2,000 scfm x 60 min/hr x 2,184 hr/yr x 0.015 grains/dscf x 1.4286E-4 lbs/grain x 2 units (Unit 4 &5)= = 0.56 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of__ -- **NA**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: a	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE10 – Visible Emissions**	2. Basis for Allowable Opacity: ☒ Rule ☐Other
3. Allowable Opacity: Normal Conditions: **5**% Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions from each dust collector fabric filter exhaust shall not exceed 5% opacity based on a 6-minute average. Please see Attachment CR-EU32-I2 for a copy of the EPA Method 9 stack test results for opacity.**	

Visible Emissions Limitation: Visible Emissions Limitation __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

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

Continuous Monitoring System: Continuous Monitor _ of _

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

EU032 - Hydrated Lime Storage and Transfer System

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___ ☒ Previously Submitted, Date **May 20, 2009**

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☒ Previously Submitted, Date **May 20, 2009**

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☒ Previously Submitted, Date **June 18, 2012**

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___ ☒ Previously Submitted, Date **May 20 ,2009**
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **CR-EU32-I1** ☐ Previously Submitted, Date ______________
   ☐ Not Applicable (construction application)

6. Compliance Demonstration Reports/Records:
   ☒ Attached, Document ID: **CR-EU32-I2**
   Test Date(s)/Pollutant(s) Tested: **October 9-10, 2013/ VE**

   ☐ Previously Submitted, Date: ______________________
   Test Date(s)/Pollutant(s) Tested: ____
   ☐ To be Submitted, Date (if known):___________________
   Test Date(s)/Pollutant(s) Tested: ____
   ☐ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☐ Attached, Document ID: ________________ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID: ___________ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ___________ ☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: CR-1
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☒ Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT CR-1
IDENTIFICATION OF APPLICABLE REQUIREMENTS

Regulation	EU Nos.
40 CFR 60, Subpart A, NSPS General Provisions	003, 004, 016
40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	003, 004
40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	029
40 CFR 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	030
40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants	023
40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	028, 029, 030
40 CFR 63, Subpart Y, Standards of Performance for Coal Preparation Plants.	016
40 CFR 75 Acid Rain Monitoring Provisions	001, 002, 003, 004
Rule 62-296.405, F.A.C.	001, 002
Rule 62-210.370, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016, 020
Rule 62-210.700, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016, 020, 033
Rule 62-213.410, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016, 020, 033
Rule 62-213.440, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016, 020, 033
Rule 62-297.310, F.A.C.	001, 002, 003, 004, 006, 008, 009, 010, 013, 014, 015, 016, 020, 033

ATTACHMENT CR-EU3-I1
COMPLIANCE DEMONSTRATION REPORTS/RECORDS
SULFURIC ACID MIST (SAM)
AUGUST-OCTOBER 2013

COMPLIANCE
TEST REPORT
FOR
DUKE ENERGY FLORIDA
CRYSTAL RIVER PLANT
UNIT 4 & 5

October 10 & 11, 2013

Job # 13-369

Test Report Date: 11-07-13

Grace Consulting, Inc.
Emissions Testing Services

November 7, 2013

I, Josh Punch, hereby certify that the data obtained for Duke Energy Florida at the Crystal River Plant on Units 4 & 5 are in accordance with procedures set forth by the USEPA. This report accurately represents the data obtained from the testing procedures and analysis of this data.

Josh Punch /MB
Josh Punch, QSTI
Crew Chief

I, Carl Vineyard, hereby certify that I have reviewed this report and to the best of my knowledge, the data presented herein is complete and accurate.

Carl Vineyard, P.E., QSTI
Test Engineer

Grace Consulting, Inc.
1855 Sipe Road
Conover, NC 28613

Toll Free: 1-877-GCI-TEST
Phone: 828-855-0217
Fax: 828-855-0217
gcitest.com

INTRODUCTION

INTRODUCTION

This report presents the results of the emissions tests performed for Duke Energy Florida at the Crystal River Plant, Units 4 & 5.

The purpose of the tests was to determine the emissions of the units for compliance. The results can be found in the Summary of Test Results section of this report.

The testing was performed by Grace Consulting, Inc., located at 1855 Sipe Road, Conover, NC 28613. Present during the testing were Josh Punch, Matt Sanford, Brian Dice and Joey Niglio from Grace Consulting, Inc. Jon Hays was present to observe the testing from Duke Energy.

The tests were performed on October 10 & 11, 2013. The testing was completed in accordance with USEPA test methods as published in the July 1, 2013 Federal Register, - "Standards of Performance for New Stationary Sources" and subsequent revisions.

The sampling and analytical procedures can be found in the Sampling and Analytical Procedures section of this report. The raw field data and the equations used to determine the final results are presented in the Appendix section.

SUMMARY OF TEST RESULTS

SUMMARY OF TEST RESULTS

The following presents the results of the emissions tests performed for Duke Energy Florida at the Crystal River Plant, Unit 4 & 5.

PARTICULATE EMISSIONS
Method 5B
Unit 4

Run #	Test Date	mg/ACM	lb/hr	lb/mmBtu
1	10-10-13	6.774	62.25	0.008
2	10-10-13	5.898	54.18	0.007
3	10-10-13	7.765	70.16	0.009
Avg.		**6.812**	**62.20**	**0.008**

AMMONIA EMISSIONS
CTM-027
Unit 4

Run #	Test Date	ppm dry	lb/hr	lb/mmBtu
1	10-10-13	0.041	0.20	2.51E-05
2	10-10-13	<0.019	<0.09	<1.16E-05
3	10-10-13	<0.021	<0.10	<1.26E-05
Avg.		**<0.027**	**<0.13**	**<1.64E-05**

H2SO4 EMISSIONS
Method 8A
Unit 4

Run #	Test Date	ppm wet	lb/hr	lb/mmBtu
1	10-10-13	1.45	48.68	0.0061
2	10-10-13	1.48	50.09	0.0062
3	10-10-13	1.45	48.27	0.0060
Avg.		**1.46**	**49.01**	**0.0061**

VISIBLE EMISSIONS
Unit 4

Run #	Test Date	Time	%Opacity
1	10-10-13	17:00-18:00	6.6

PARTICULATE EMISSIONS
Method 5B
Unit 5

Run #	Test Date	mg/ACM	lbs/hr	lb/mmBtu
1	10-11-13	7.967	73.24	0.009
2	10-11-13	5.380	49.13	0.006
3	10-11-13	7.549	69.55	0.008
Avg.		**6.965**	**63.97**	**0.008**

AMMONIA EMISSIONS
CTM-027
Unit 5

Run #	Test Date	ppm dry	lbs/hr	lb/mmBtu
1	10-11-13	<0.021	<0.10	<1.26E-05
2	10-11-13	0.044	0.22	2.71E-05
3	10-11-13	<0.017	<0.09	<1.05E-05
Avg.		**<0.027**	**<0.14**	**<1.67E-05**

H2SO4 EMISSIONS
Method 8A
Unit 5

Run #	Test Date	ppm wet	lb/hr	lb/mmBtu
1	10-11-13	0.96	31.86	0.0039
2	10-11-13	0.91	30.19	0.0037
3	10-11-13	1.08	35.86	0.0044
Avg.		**0.98**	**32.64**	**0.0040**

VISIBLE EMISSIONS
Unit 5

Run #	Test Date	Time	%Opacity
1	10-11-13	14:15-15:15	5.6

The complete results can be found on the computer printouts following.

Grace Consulting, Inc.

Particulate Analysis

Duke Energy Florida
Crystal River
Unit 4
13-364

Run Number			1	2	3
Date			10/10/2013	10/10/2013	10/10/2013
Location			Unit 4	Unit 4	Unit 4
Comment			Method 5B	Method 5B	Method 5B
Start Time			12:00	15:25	18:00
End Time			14:19	17:39	20:13
Barometric Pressure	In. Hg.	Pb	29.60	29.60	29.60
Static Pressure	In. H2O	Pf	-0.54	-0.62	-0.59
Condensate Collected	grams	Vlc	340.7	343.6	337.2
Volume Sampled	dcf	Vm	89.742	87.834	86.189
Meter Correction Factor		Y	0.996	0.996	0.996
Pitot Tube Correction Factor		Pc	0.840	0.840	0.840
Square Root of Delta P			0.905	0.906	0.891
Orifice Pressure	In. H2O		1.598	1.643	1.580
Meter Temperature	Degree F		101	104	103
Flue Temperature	Degree F		127	126	126
Percent CO2	%		13.00	12.90	12.90
Percent O2	%		6.20	6.40	6.10
Diameter of Nozzle	In.		0.224	0.224	0.224
Area of Flue	Sq. ft.		754.768	754.768	754.768
Sample Time	min.		120	120	120
Weight Gain	grams		0.0210	0.0177	0.0229
F-Factor			9,780	9,780	9,780
Absolute Flue Pressure	in. Hg	Ps	29.56	29.55	29.56
Corrected Sample Volume	dscf	Vms	83.56	81.35	79.96
Measured Moisture of Flue Gas	%	Bws	16.13%	16.61%	16.59%
Calculated Saturated Moisture	%	Bwsat	14.12%	13.75%	13.75%
Moisture used for Calculations	%	Bwsu	14.12%	13.75%	13.75%
Molecular Weight	lb/lb-mole	Ms	28.59	28.63	28.62
Velocity of Flue Gas	fps	Vs	54.17	54.15	53.26
Volume of Flue Gas	ACFM	Vo	2,452,937	2,452,125	2,411,867
Volume of Flue Gas	DSCFM	Qsd	1,872,061	1,882,397	1,851,653
Dust Concentration	lb/dscf	Wd	5.54E-07	4.80E-07	6.32E-07
Dust Concentration	lb/hr	Wh	62.25	54.18	70.16
Dust Concentration	gr/acf	Wa	2.96E-03	2.58E-03	3.39E-03
Dust Concentration	gr/dscf	Ws	3.88E-03	3.36E-03	4.42E-03
Isokinetic Rate	%	%I	105.0	102.7	102.6
Sample Volume @ Stack Conditions	dacm	Vstack	2.6624	2.5884	2.5438
Sample Volume @ Standard Cond	dscm	Vms (metric)	2.3660	2.3037	2.2642
Particulate Concentration	mg/acm (wet)	Cpm(stack)	6.774	5.898	7.765
Particulate Concentration	mg/wscm		7.622	6.627	8.724
Particulate Concentration	mg/DSCM		8.876	7.683	10.114
Particulate Concentration	mg/Ncm		7.622	6.627	8.724
Particulate Emissions	lb/mmBtu	DI	0.008	0.007	0.009
Approximate Heat Input	mmBtu/hr		8077.991	8012.079	8044.284

Averages:	Flue Temp.:	126.3	lb/dscf	5.55E-07
	ACFM:	2,438,976	lb/hr	62.20
	DSCFM:	1,868,703	gr/acf	2.98E-03
	Percent O2:	6.23%	gr/dscf	3.89E-03
	mmBtu/hr	8044.785	lb/mmBtu	0.008

GRACE CONSULTING, INC.

Ammonia Analysis

Duke Energy Florida
Crystal River
Unit 4
13-364

Run Number			1	2	3
Date			10/10/2013	10/10/2013	10/10/2013
Location			Unit 4	Unit 4	Unit 4
Comment			CTM-027	CTM-027	CTM-027
Start Time			12:00	15:25	18:00
End Time			14:19	17:39	20:13
Barometric Pressure	In. Hg.	Pb	29.60	29.60	29.60
Static Pressure	In. H2O	Pf	-0.54	-0.62	-0.59
Condensate Collected	grams	Vlc	340.7	343.6	337.2
Volume Sampled	dcf	Vm	89.742	87.834	86.189
Meter Correction Factor		Y	0.996	0.996	0.996
Pitot Tube Correction Factor		Pc	0.840	0.840	0.840
Square Root of Delta P			0.905	0.906	0.891
Orifice Pressure	In. H2O		1.598	1.643	1.580
Meter Temperature	Degree F		101	104	103
Flue Temperature	Degree F		127	126	126
Percent CO2	%		13.00	12.90	12.90
Percent O2	%		6.20	6.40	6.10
Diameter of Nozzle	In.		0.224	0.224	0.224
Area of Flue	Sq. ft.		754.768	754.768	754.768
Sample Time	min.		120	120	120
Ammonia Collected	grams		0.0000685	< 0.0000304	< 0.0000330
F-Factor			9,780	9,780	9,780
Absolute Flue Pressure	in. Hg	Ps	29.56	29.55	29.56
Corrected Sample Volume	dscf	Vms	83.56	81.35	79.96
Measured Moisture of Flue Gas	%	Bws	16.13%	16.61%	16.59%
Calculated Saturated Moisture	%	Bwsat	14.12%	13.75%	13.75%
Moisture used for Calculations	%	Bwsu	14.12%	13.75%	13.75%
Molecular Weight	lb/lb-mole	Ms	28.59	28.63	28.62
Velocity of Flue Gas	fps	Vs	54.17	54.15	53.26
Volume of Flue Gas	ACFM	Vo	2,452,937	2,452,125	2,411,867
Volume of Flue Gas	DSCFM	Qsd	1,872,061	1,882,397	1,851,653
Ammonia Concentration	lb/dscf	Wd	1.81E-09	< 8.24E-10	< 9.10E-10
Ammonia Concentration	ppm		0.041	< 0.019	< 0.021
Ammonia Concentration	lb/hr	Wh	0.20	< 0.09	< 0.10
Ammonia Concentration	gr/acf	Wa	9.66E-06	< 4.43E-06	< 4.89E-06
Ammonia Concentration	gr/dscf	Ws	1.27E-05	< 5.77E-06	< 6.37E-06
Isokinetic Rate	%	%I	105.0	102.7	102.6
Sample Volume @ Stack Conditions	dacm	Vstack	2.6624	< 2.5884	< 2.5438
Sample Volume @ Standard Cond	dscm	Vms (metric)	2.3660	< 2.3037	< 2.2642
Ammonia Concentration	mg/acm (wet)	Cpm(stack)	0.022	< 0.010	< 0.011
Ammonia Concentration	mg/wscm		0.025	< 0.011	< 0.013
Ammonia Concentration	mg/DSCM		0.029	< 0.013	< 0.015
Ammonia Concentration	mg/Ncm		0.025	< 0.011	< 0.013
Ammoniae Emissions	lb/mmBtu	DI	2.51E-05	< 1.16E-05	< 1.26E-05
Approximate Heat Input	mmBtu/hr		8077.991	< 8012.079	< 8044.284

Averages:	Flue Temp.:	126.3	lb/dscf	<	1.18E-09
	ACFM:	2,438,976	ppm	<	0.027
	DSCFM:	1,868,703	lb/hr	<	0.13
	Percent O2:	6.23%	gr/acf	<	6.33E-06
	mmBtu/hr	8044.785	gr/dscf	<	8.26E-06
			lb/mmBtu	<	1.64E-05

Mois Calc 1

Alternative methods for determination of moisture content in stack gas:

	%M	Tf	Tw	Td	Pb	P(abs)	P static		
Saturation Vapor Perssure Table:	0.141203	127	127	127	29.6	29.56029	-0.54	Percent Moisture	14.12
	RH	Tf	Tw	Td	Pb	P(abs)	Lb/Lb		
Psychrometric Calculation:	100	127.00	127	127.00	29.6	29.56029	-0.622		

Water Vapor Pressure in gas mixture passing a wet and dry bulb thermometer assembly (	4.1734	ea
Proportion by volume of water vapor in gas mixture for saturated conditions (Bw):	0.141203	bw
Water Vapor pressure at saturated conditions and wet bulb temperature (E'):	4.174	e' From Wvp_Table
Absolute pressure of a gas mixture (Pmix):	29.56029	Pmix
Proportion by volume of water vapor in a gas (Bwo):	0.141183	Bwo
Absolute pressure at the wet bulb and dry bulb temperature assembly (Pa):	29.56029	Pa
Water vapor pressure in a gas mixture (Eo):	4.1734	eo
Absolute pressure of duct gas (Po):	29.56029	Po

Temperature Dry Bulb deg. F	Wet Bulb deg. F	Barometric Pressure PSIA	Specific Humidity	Relative Humidity %	stm32	stm	sps	spa	sw	c12	c13	w
127	127	0	-0.622	100	2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

100% Relative Humidity Calculations Appear Below This Point.

stm32	stm	sps	spa	sw	c12	c13	w
2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

Mois Calc 2

Alternative methods for determination of moisture content in stack gas:

	%M	Tf	Tw	Td	Pb	P(abs)	P static		
Saturation Vapor Perssure Table:	0.137475	126	126	126	29.6	29.55441	-0.62	Percent Moisture	13.75
	RH	Tf	Tw	Td	Pb	P(abs)	Lb/Lb		
Psychrometric Calculation:	100	126.00	126	126.00	29.6	29.55441	-0.622		

Water Vapor Pressure in gas mixture passing a wet and dry bulb thermometer assembly (	4.0624	ea
Proportion by volume of water vapor in gas mixture for saturated conditions (Bw):	0.137475	bw
Water Vapor pressure at saturated conditions and wet bulb temperature (E'):	4.063	e' From Wvp_Table
Absolute pressure of a gas mixture (Pmix):	29.55441	Pmix
Proportion by volume of water vapor in a gas (Bwo):	0.137455	Bwo
Absolute pressure at the wet bulb and dry bulb temperature assembly (Pa):	29.55441	Pa
Water vapor pressure in a gas mixture (Eo):	4.0624	eo
Absolute pressure of duct gas (Po):	29.55441	Po

Temperature Dry Bulb deg. F	Wet Bulb deg. F	Barometric Pressure PSIA	Specific Humidity	Relative Humidity %	stm32	stm	sps	spa	sw	c12	c13	w
126	126	0	-0.622	100	2.847691	1.996595	1.996595	-1.9966	-0.622	1021.684	0	-0.622

100% Relative Humidity Calculations Appear Below This Point.

stm32	stm	sps	spa	sw	c12	c13	w
2.847691	1.996595	1.996595	-1.9966	-0.622	1021.684	0	-0.622

Mois Calc 3

Alternative methods for determination of moisture content in stack gas:

	%M	Tf	Tw	Td	Pb	P(abs)	P static		
Saturation Vapor Perssure Table:	0.137465	126	126	126	29.6	29.55662	-0.59	Percent Moisture	13.75
	RH	Tf	Tw	Td	Pb	P(abs)	Lb/Lb		
Psychrometric Calculation:	100	126.00	126	126.00	29.6	29.55662	-0.622		

Water Vapor Pressure in gas mixture passing a wet and dry bulb thermometer assembly (	4.0624	ea
Proportion by volume of water vapor in gas mixture for saturated conditions (Bw):	0.137465	bw
Water Vapor pressure at saturated conditions and wet bulb temperature (E'):	4.063	e' From Wvp_Table
Absolute pressure of a gas mixture (Pmix):	29.55662	Pmix
Proportion by volume of water vapor in a gas (Bwo):	0.137445	Bwo
Absolute pressure at the wet bulb and dry bulb temperature assembly (Pa):	29.55662	Pa
Water vapor pressure in a gas mixture (Eo):	4.0624	eo
Absolute pressure of duct gas (Po):	29.55662	Po

Temperature Dry Bulb deg. F	Wet Bulb deg. F	Barometric Pressure PSIA	Specific Humidity	Relative Humidity %	stm32	stm	sps	spa	sw	c12	c13	w
126	126	0	-0.622	100	2.847691	1.996595	1.996595	-1.9966	-0.622	1021.684	0	-0.622

100% Relative Humidity Calculations Appear Below This Point.

stm32	stm	sps	spa	sw	c12	c13	w
2.847691	1.996595	1.996595	-1.9966	-0.622	1021.684	0	-0.622

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 4
Method 5B

Date: 10/10/2013
Pollutant: CO2
Monitor Span: 18.14

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Gas	Corrected Percent, Dry Basis
1	12.88	0.15	0.11	-0.22	9.11	8.98	-0.72	9.071	13.00
2	12.77	0.11	0.05	-0.33	8.98	9.06	0.44	9.071	12.90
3	12.95	0.05	0.08	0.17	9.06	9.14	0.44	9.071	12.90

$$\mathrm{Cgas} = (\mathrm{Cavg} - \mathrm{Co}) * \mathrm{Cma} / (\mathrm{Cm} - \mathrm{Co}) \qquad \text{Eq. 6C-1}$$

where:

Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 4
Method 5B

Date: 10/10/2013
Pollutant: O2
Monitor Span: 21.96

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Calibration Gas	Corrected Percent, Dry Basis
1	6.29	0.11	0.05	-0.27	10.95	11.13	0.82	10.93	6.20
2	6.47	0.05	0.16	0.50	11.13	10.99	-0.64	10.93	6.40
3	6.26	0.16	0.10	-0.27	10.99	11.14	0.68	10.93	6.10

$$Cgas = (Cavg - Co) * Cma / (Cm - Co) \qquad \text{Eq. 6C-1}$$

where:

Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

GRACE CONSULTING, INC.

H2SO4 Analysis

Duke Energy Florida
Crystal River
Unit 4
13-369

Run Number			1	2	3
Date			10/10/2013	10/10/2013	10/10/2013
Location			Unit 4	Unit 4	Unit 4
Comment			Method 8A	Method 8A	Method 8A
Start Time			12:00	15:25	18:00
End Time			13:00	16:25	19:00
Barometric Pressure	In. Hg.	Pb	29.6	29.6	29.6
Static Pressure	In. H2O	Pf	-0.54	-0.62	-0.59
Volume Sampled	dcf	Vm	20.698	20.795	21.424
Meter Correction Factor		Y	1.001	1.001	1.001
Pitot Tube Correction Factor		Pc	0.840	0.840	0.840
Square Root of Delta P			0.905	0.906	0.891
Orifice Pressure	In. H2O		0.45	0.45	0.45
Meter Temperature	Degree F		91	95	95
Flue Temperature	Degree F		127	126	126
Percent CO2	%		12.9	13.00	12.90
Percent O2	%		6.30	6.30	6.10
Area of Flue	Sq. ft.		754.768	754.768	754.768
Sample Time	min.		30	30	60
H2SO4 Collected	grams		0.0038645	0.0039455	0.0039815
F-Factor			9,780	9,780	9,780
Absolute Flue Pressure	in. Hg	Ps	29.56	29.55	29.56
Corrected Sample Volume	dscf	Vms	19.66	19.61	20.21
Calculated Saturated Moisture	%	Bwsat	14.12%	13.75%	13.75%
Moisture used for Calculations	%	Bwsu	14.12%	13.75%	13.75%
Molecular Weight	lb/lb-mole	Ms	28.58	28.64	28.62
Velocity of Flue Gas	fps	Vs	54.18	54.14	53.26
Volume of Flue Gas	ACFM	Vo	2,453,379	2,451,681	2,411,867
Volume of Flue Gas	DSCFM	Qsd	1,872,398	1,882,056	1,851,653
H2SO4 Concentration	lb/dscf	Wd	4.33E-07	4.44E-07	4.34E-07
H2SO4 Concentration	ppm dry		1.71	1.75	1.71
H2SO4 Concentration	ppm wet		1.45	1.48	1.45
H2SO4 Concentration	lb/hr	Wh	48.68	50.09	48.27
H2SO4 Concentration	gr/acf	Wa	2.32E-03	2.38E-03	2.33E-03
H2SO4 Concentration	gr/dscf	Ws	3.03E-03	3.10E-03	3.04E-03
H2SO4 Emissions	lb/mmBtu	DI	0.0061	0.0062	0.0060

Averages:	Flue Temp.:	126.3333	H2SO4 Emis:	lb/dscf	4.37E-07
	ACFM:	2,438,976		lb/hr	49.01
	DSCFM:	1,868,703		gr/acf	2.34E-03
	Percent O2:	6.23%		gr/dscf	3.06E-03
	H2SO4 ppm wet:	1.46		lb/mmBtu	0.0061

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 4

Date: 10/10/2013
Pollutant: CO2
Monitor Span: 18.14

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Gas	Corrected Percent, Dry Basis
1	12.84	0.15	0.11	-0.22	9.11	8.98	-0.72	9.071	12.90
2	12.89	0.11	0.05	-0.33	8.98	9.06	0.44	9.071	13.00
3	12.89	0.05	0.08	0.17	9.06	9.14	0.44	9.071	12.90

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:

Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 4

Date: 10/10/2013
Pollutant: O2
Monitor Span: 21.96

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Calibration Gas	Corrected Percent, Dry Basis
1	6.37	0.11	0.05	-0.27	10.95	11.13	0.82	10.93	6.30
2	6.42	0.05	0.16	0.50	11.13	10.99	-0.64	10.93	6.30
3	6.23	0.16	0.10	-0.27	10.99	11.14	0.68	10.93	6.10

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:
Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

GRACE CONSULTING, INC.

Particulate Analysis

Duke Energy Florida
Crystal River
Unit 5
13-364

Run Number			1	2	3
Date			10/11/2013	10/11/2013	10/11/2013
Location			Unit 5	Unit 5	Unit 5
Comment			Method 5B	Method 5B	Method 5B
Start Time			11:00	14:15	16:50
End Time			13:14	16:29	19:03
Barometric Pressure	In. Hg.	Pb	29.62	29.62	29.62
Static Pressure	In. H2O	Pf	-0.57	-0.63	-0.55
Condensate Collected	grams	Vlc	352.7	369.1	372.8
Volume Sampled	dcf	Vm	86.894	86.914	87.583
Meter Correction Factor		Y	0.996	0.996	0.996
Pitot Tube Correction Factor		Pc	0.840	0.840	0.840
Square Root of Delta P			0.906	0.900	0.908
Orifice Pressure	In. H2O		1.610	1.615	1.628
Meter Temperature	Degree F		99	103	102
Flue Temperature	Degree F		127	127	127
Percent CO2	%		13.20	13.20	13.20
Percent O2	%		6.10	6.20	6.00
Diameter of Nozzle	In.		0.224	0.224	0.224
Area of Flue	Sq. ft.		754.768	754.768	754.768
Sample Time	min.		120	120	120
Weight Gain	grams		0.0240	0.0161	0.0228
F-Factor			9,780	9,780	9,780
Absolute Flue Pressure	in. Hg	Ps	29.58	29.57	29.58
Corrected Sample Volume	dscf	Vms	81.25	80.69	81.46
Measured Moisture of Flue Gas	%	Bws	16.99%	17.74%	17.75%
Calculated Saturated Moisture	%	Bwsat	14.11%	14.11%	14.11%
Moisture used for Calculations	%	Bwsu	14.11%	14.11%	14.11%
Molecular Weight	lb/lb-mole	Ms	28.61	28.62	28.61
Velocity of Flue Gas	fps	Vs	54.19	53.83	54.31
Volume of Flue Gas	ACFM	Vo	2,453,832	2,437,628	2,459,331
Volume of Flue Gas	DSCFM	Qsd	1,874,056	1,861,358	1,878,365
Dust Concentration	lb/dscf	Wd	6.51E-07	4.40E-07	6.17E-07
Dust Concentration	lb/hr	Wh	73.24	49.13	69.55
Dust Concentration	gr/acf	Wa	3.48E-03	2.35E-03	3.30E-03
Dust Concentration	gr/dscf	Ws	4.56E-03	3.08E-03	4.32E-03
Isokinetic Rate	%	%I	103.1	104.0	104.1
Sample Volume @ Stack Conditions	dacm	Vstack	2.5874	2.5701	2.5940
Sample Volume @ Standard Cond	dscm	Vms (metric)	2.3008	2.2850	2.3067
Particulate Concentration	mg/acm (wet)	Cpm(stack)	7.967	5.380	7.549
Particulate Concentration	mg/wscm		8.959	6.052	8.489
Particulate Concentration	mg/DSCM		10.431	7.046	9.884
Particulate Concentration	mg/Ncm		8.959	6.052	8.489
Particulate Emissions	lb/mmBtu	DI	0.009	0.006	0.008
Approximate Heat Input	mmBtu/hr		8141.613	8031.807	8215.470

Averages:	Flue Temp.:	127.0	lb/dscf	5.69E-07
	ACFM:	2,450,264	lb/hr	63.97
	DSCFM:	1,871,260	gr/acf	3.04E-03
	Percent O2:	6.10%	gr/dscf	3.99E-03
	mmBtu/hr	8129.630	lb/mmBtu	0.008

GRACE CONSULTING, INC.

Ammonia Analysis

Duke Energy Florida
Crystal River
Unit 5
13-364

Run Number			1	2	3
Date			10/11/2013	10/11/2013	10/11/2013
Location			Unit 5	Unit 5	Unit 5
Comment			CTM-027	CTM-027	CTM-027
Start Time			11:00	14:15	16:50
End Time			13:14	16:29	19:03
Barometric Pressure	In. Hg.	Pb	29.62	29.62	29.62
Static Pressure	In. H2O	Pf	-0.57	-0.63	-0.55
Condensate Collected	grams	Vlc	352.7	369.1	372.8
Volume Sampled	dcf	Vm	86.894	86.914	87.583
Meter Correction Factor		Y	0.996	0.996	0.996
Pitot Tube Correction Factor		Pc	0.840	0.840	0.840
Square Root of Delta P			0.906	0.900	0.908
Orifice Pressure	In. H2O		1.610	1.615	1.628
Meter Temperature	Degree F		99	103	102
Flue Temperature	Degree F		127	127	127
Percent CO2	%		13.20	13.20	13.20
Percent O2	%		6.10	6.20	6.00
Diameter of Nozzle	In.		0.224	0.224	0.224
Area of Flue	Sq. ft.		754.768	754.768	754.768
Sample Time	min.		120	120	120
Ammonia Collected	grams		< 0.0000335	0.0000713	< 0.0000284
F-Factor			9,780	9,780	9,780
Absolute Flue Pressure	in. Hg	Ps	29.58	29.57	29.58
Corrected Sample Volume	dscf	Vms	81.25	80.69	81.46
Measured Moisture of Flue Gas	%	Bws	16.99%	17.74%	17.75%
Calculated Saturated Moisture	%	Bwsat	14.11%	14.11%	14.11%
Moisture used for Calculations	%	Bwsu	14.11%	14.11%	14.11%
Molecular Weight	lb/lb-mole	Ms	28.61	28.62	28.61
Velocity of Flue Gas	fps	Vs	54.19	53.83	54.31
Volume of Flue Gas	ACFM	Vo	2,453,832	2,437,628	2,459,331
Volume of Flue Gas	DSCFM	Qsd	1,874,056	1,861,358	1,878,365
Ammonia Concentration	lb/dscf	Wd	< 9.09E-10	1.95E-09	< 7.69E-10
Ammonia Concentration	ppm		< 0.021	0.044	< 0.017
Ammonia Concentration	lb/hr	Wh	< 0.10	0.22	< 0.09
Ammonia Concentration	gr/acf	Wa	< 4.86E-06	1.04E-05	< 4.11E-06
Ammonia Concentration	gr/dscf	Ws	< 6.36E-06	1.36E-05	< 5.38E-06
Isokinetic Rate	%	%I	103.1	104.0	104.1
Sample Volume @ Stack Conditions	dacm	Vstack	< 2.5874	2.5701	< 2.5940
Sample Volume @ Standard Cond	dscm	Vms (metric)	< 2.3008	2.2850	< 2.3067
Ammonia Concentration	mg/acm (wet)	Cpm(stack)	< 0.011	0.024	< 0.009
Ammonia Concentration	mg/wscm		< 0.013	0.027	< 0.011
Ammonia Concentration	mg/DSCM		< 0.015	0.031	< 0.012
Ammonia Concentration	mg/Ncm		< 0.013	0.027	< 0.011
Ammonia Emissions	lb/mmBtu	DI	< 1.26E-05	2.71E-05	< 1.05E-05
Approximate Heat Input	mmBtu/hr		< 8141.613	8031.807	< 8215.470

Averages:	Flue Temp.:	127.0	lb/dscf	<	1.21E-09
	ACFM:	2,450,264	ppm	<	0.027
	DSCFM:	1,871,260	lb/hr	<	0.14
	Percent O2:	6.10%	gr/acf	<	6.46E-06
	mmBtu/hr	8129.630	gr/dscf	<	8.46E-06
			lb/mmBtu	<	1.67E-05

Mois Calc 1

Alternative methods for determination of moisture content in stack gas:

	%M	Tf	Tw	Td	Pb	P(abs)	P static		
Saturation Vapor Perssure Table:	0.141118	127	127	127	29.62	29.57809	-0.57	Percent Moisture	14.11
	RH	Tf	Tw	Td	Pb	P(abs)	Lb/Lb		
Psychrometric Calculation:	100	127.00	127	127.00	29.62	29.57809	-0.622		

Water Vapor Pressure in gas mixture passing a wet and dry bulb thermometer assembly (	4.1734	ea
Proportion by volume of water vapor in gas mixture for saturated conditions (Bw):	0.141118	bw
Water Vapor pressure at saturated conditions and wet bulb temperature (E'):	4.174	e' From Wvp_Table
Absolute pressure of a gas mixture (Pmix):	29.57809	Pmix
Proportion by volume of water vapor in a gas (Bwo):	0.141098	Bwo
Absolute pressure at the wet bulb and dry bulb temperature assembly (Pa):	29.57809	Pa
Water vapor pressure in a gas mixture (Eo):	4.1734	eo
Absolute pressure of duct gas (Po):	29.57809	Po

Temperature Dry Bulb deg. F	Wet Bulb deg. F	Barometric Pressure PSIA	Specific Humidity	Relative Humidity %	stm32	stm	sps	spa	sw	c12	c13	w
127	127	0	-0.622	100	2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

100% Relative Humidity Calculations Appear Below This Point.

stm32	stm	sps	spa	sw	c12	c13	w
2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

Mois Calc 2

Alternative methods for determination of moisture content in stack gas:

	%M	Tf	Tw	Td	Pb	P(abs)	P static		
Saturation Vapor Perssure Table:	0.141139	127	127	127	29.62	29.57368	-0.63	Percent Moisture	14.11
	RH	Tf	Tw	Td	Pb	P(abs)	Lb/Lb		
Psychrometric Calculation:	100	127.00	127	127.00	29.62	29.57368	-0.622		

Water Vapor Pressure in gas mixture passing a wet and dry bulb thermometer assembly (	4.1734	ea
Proportion by volume of water vapor in gas mixture for saturated conditions (Bw):	0.141139	bw
Water Vapor pressure at saturated conditions and wet bulb temperature (E'):	4.174	e' From Wvp_Table
Absolute pressure of a gas mixture (Pmix):	29.57368	Pmix
Proportion by volume of water vapor in a gas (Bwo):	0.141119	Bwo
Absolute pressure at the wet bulb and dry bulb temperature assembly (Pa):	29.57368	Pa
Water vapor pressure in a gas mixture (Eo):	4.1734	eo
Absolute pressure of duct gas (Po):	29.57368	Po

Temperature Dry Bulb deg. F	Wet Bulb deg. F	Barometric Pressure PSIA	Specific Humidity	Relative Humidity %	stm32	stm	sps	spa	sw	c12	c13	w
127	127	0	-0.622	100	2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

100% Relative Humidity Calculations Appear Below This Point.

stm32	stm	sps	spa	sw	c12	c13	w
2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

Mois Calc 3

Alternative methods for determination of moisture content in stack gas:

	%M	Tf	Tw	Td	Pb	P(abs)	P static		
Saturation Vapor Perssure Table:	0.141111	127	127	127	29.62	29.57956	-0.55	Percent Moisture	14.11
	RH	Tf	Tw	Td	Pb	P(abs)	Lb/Lb		
Psychrometric Calculation:	100	127.00	127	127.00	29.62	29.57956	-0.622		

Water Vapor Pressure in gas mixture passing a wet and dry bulb thermometer assembly (	4.1734	ea
Proportion by volume of water vapor in gas mixture for saturated conditions (Bw):	0.141111	bw
Water Vapor pressure at saturated conditions and wet bulb temperature (E'):	4.174	e' From Wvp_Table
Absolute pressure of a gas mixture (Pmix):	29.57956	Pmix
Proportion by volume of water vapor in a gas (Bwo):	0.141091	Bwo
Absolute pressure at the wet bulb and dry bulb temperature assembly (Pa):	29.57956	Pa
Water vapor pressure in a gas mixture (Eo):	4.1734	eo
Absolute pressure of duct gas (Po):	29.57956	Po

Temperature Dry Bulb deg. F	Wet Bulb deg. F	Barometric Pressure PSIA	Specific Humidity	Relative Humidity %	stm32	stm	sps	spa	sw	c12	c13	w
127	127	0	-0.622	100	2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

100% Relative Humidity Calculations Appear Below This Point.

stm32	stm	sps	spa	sw	c12	c13	w
2.931112	2.051414	2.051414	-2.05141	-0.622	1021.118	0	-0.622

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 5
Method 5B

Date: 10/11/2013
Pollutant: CO2
Monitor Span: 18.14

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Gas	Corrected Percent, Dry Basis
1	13.14	0.09	0.16	0.39	9.05	9.15	0.55	9.071	13.20
2	13.10	0.16	0.13	-0.17	9.15	8.97	-0.99	9.071	13.20
3	13.16	0.13	0.02	-0.61	8.97	9.12	0.83	9.071	13.20

$$Cgas = (Cavg - Co) * Cma / (Cm - Co) \qquad \text{Eq. 6C-1}$$

where:

Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 5
Method 5B

Date: 10/11/2013
Pollutant: O2
Monitor Span: 21.96

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Calibration Gas	Corrected Percent, Dry Basis
1	6.18	0.13	0.05	-0.36	10.99	10.92	-0.32	10.93	6.10
2	6.24	0.05	0.11	0.27	10.92	11.06	0.64	10.93	6.20
3	6.16	0.11	0.16	0.23	11.06	11.11	0.23	10.93	6.00

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:

Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

Grace Consulting, Inc.
H2SO4 Analysis

Duke Energy Florida
Crystal River
Unit 5
13-369

Run Number			1	2	3
Date			10/11/2013	10/11/2013	10/11/2013
Location			Unit 5	Unit 5	Unit 5
Comment			Method 8A	Method 8A	Method 8A
Start Time			11:00	14:15	16:50
End Time			12:00	15:15	17:50
Barometric Pressure	In. Hg.	Pb	29.62	29.62	29.62
Static Pressure	In. H2O	Pf	-0.57	-0.63	-0.55
Volume Sampled	dcf	Vm	21.158	20.79	20.611
Meter Correction Factor		Y	1.001	1.001	1.001
Pitot Tube Correction Factor		Pc	0.840	0.840	0.840
Square Root of Delta P			0.906	0.9	0.908
Orifice Pressure	In. H2O		0.45	0.45	0.45
Meter Temperature	Degree F		94	95	96
Flue Temperature	Degree F		127	127	127
Percent CO2	%		13.20	13.20	13.20
Percent O2	%		6.10	6.10	6.00
Area of Flue	Sq. ft.		754.768	754.768	754.768
Sample Time	min.		60	60	60
H2SO4 Collected	grams		0.0025707	0.0024057	0.0028017
F-Factor			9,780	9,780	9,780
Absolute Flue Pressure	in. Hg	Ps	29.58	29.57	29.58
Corrected Sample Volume	dscf	Vms	20.01	19.62	19.42
Calculated Saturated Moisture	%	Bwsat	14.11%	14.11%	14.11%
Moisture used for Calculations	%	Bwsu	14.11%	14.11%	14.11%
Molecular Weight	lb/lb-mole	Ms	28.61	28.61	28.61
Velocity of Flue Gas	fps	Vs	54.19	53.83	54.31
Volume of Flue Gas	ACFM	Vo	2,453,832	2,437,774	2,459,331
Volume of Flue Gas	DSCFM	Qsd	1,874,056	1,861,469	1,878,365
H2SO4 Concentration	lb/dscf	Wd	2.83E-07	2.70E-07	3.18E-07
H2SO4 Concentration	ppm dry		1.12	1.06	1.25
H2SO4 Concentration	ppm wet		0.96	0.91	1.08
H2SO4 Concentration	lb/hr	Wh	31.86	30.19	35.86
H2SO4 Concentration	gr/acf	Wa	1.51E-03	1.45E-03	1.70E-03
H2SO4 Concentration	gr/dscf	Ws	1.98E-03	1.89E-03	2.23E-03
H2SO4 Emissions	lb/mmBtu	DI	0.0039	0.0037	0.0044

Averages:	Flue Temp.:	127	H2SO4 Emis:	lb/dscf	2.91E-07
	ACFM:	2,450,312		lb/hr	32.64
	DSCFM:	1,871,297		gr/acf	1.55E-03
	Percent O2:	6.07%		gr/dscf	2.03E-03
	H2SO4 ppm wet:	0.98		lb/mmBtu	0.0040

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 5

Date: 10/11/2013
Pollutant: CO2
Monitor Span: 18.14

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Gas	Corrected Percent, Dry Basis
1	13.17	0.09	0.16	0.39	9.05	9.15	0.55	9.071	13.20
2	13.10	0.16	0.13	-0.17	9.15	8.97	-0.99	9.071	13.20
3	13.15	0.13	0.02	-0.61	8.97	9.12	0.83	9.071	13.20

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:

Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Duke Energy Florida
Crystal River - Unit 5

Date: 10/11/2013
Pollutant: O2
Monitor Span: 21.96

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Calibration Gas	Corrected Percent, Dry Basis
1	6.16	0.13	0.05	-0.36	10.99	10.92	-0.32	10.93	6.10
2	6.19	0.05	0.11	0.27	10.92	11.06	0.64	10.93	6.10
3	6.16	0.11	0.16	0.23	11.06	11.11	0.23	10.93	6.00

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:
Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

DUKE
ENERGY.

Robby A. Odom
Station Manager, Crystal River
Steam Plant & Fuel Operations

October 30, 2013

Submitted electronically: ftp://ftp.dep.state.fl.us/pub/incoming

Mr. Erin Anthony DiBacco
Environmental Manager - Compliance & Enforcement
Florida Department of Environmental Protection
Southwest District
13051 N. Telecom Parkway
Temple Terrace, FL 33637

Dear Mr. DiBacco:

Re: **Submittal of Compliance Test Report**
Crystal River Facility
Facility ID: 0170004
EU-004 and EU-003 (Unit 4 & Unit 5)

As required by our Title V Air Operation Permit No. 017004-035-AV, Duke Energy Florida respectfully submits the attached compliance test reports conducted on Crystal River Power Plant Unit 4 and Unit 5.

These tests were conducted on September 17 and 18, 2013 in accordance with permit Specific Condition in Section III.B.33 and III.B.25. Each Unit was tested for sulfuric acid mist (SAM), particulate matter (PM), visible emissions (VE) and ammonia (NH3) slip.

The results show that compliance for the above requirements were demonstrated by both Units with the following exception: Crystal River Unit 4 did not achieve compliance with the SAM standard. Please note that this Unit was able to successfully achieve compliance during a follow-up test conducted on October 9, 2013. The test report for that date will be submitted to the Department at a later date.

If you have any questions concerning the contents of this submittal, please contact Mr. Jamie Hunter (727) 820-5764 or Ms. Cynthia Wilkinson (352) 501-5153.

I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

Sincerely,

for Rob Odom

Robby A. Odom
Station Manager, Crystal River Steam Plant & Fuel Operations

Enclosure – Compliance Test Reports 20-6542-04-001 & 20-6542-05-001

Air Emissions Test Report

Completed for:

Duke Energy Florida, Inc.
Crystal River Energy Complex
Unit 4 (EU -004)

Test Report Number: 20-6542-04-001

Test Completed: September 17, 2013

C.E.M. SOLUTIONS

1183 East Overdrive Circle • Hernando, FL 34442 • (352) 489-4337 • Fax: (352) 489-4801

Air Emissions Test Report

Duke Energy Florida, Inc.
Crystal River, Unit 4 (EU -004)
Crystal River, Florida

C.E.M. Solutions Project No.: 6542

Testing Completed: September 17, 2013

C.E.M. Solutions, Inc. Report Number: 20-6542-04-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Declaration of Conformance to ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies

C.E.M. Solutions operates in conformance with the requirements of ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies through the use of a quality system which incorporates a quality manual, internal audit system, systematic training of personnel and rigorous review of test methods and operating procedures.

Joe Conti
Quality Assurance Manager
C.E.M. Solutions

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at the Duke Energy Florida Inc. Crystal River facility conducted on September 17, 2013 are complete and accurate to the best of my knowledge.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner:	Duke Energy
Address of Owner:	One Power Plaza 299 First Avenue North St. Petersburg, FL 33701
Source Identification:	Facility: 0170004 Emissions Unit: EU-004
Location of Source:	Citrus County, Florida
Type of Operation:	SIC Code 4911
Tests Performed:	Method 1 – Traverse Points Method 2 – Stack Gas Volumetric Flow and Velocity Method 3A – Determination of Molecular Weight Method 4 – Stack Gas Moisture Content Method 5B – Particulate Matter NCASI Method 8A – Sulfuric Acid Mist Method 9 – Determination of Opacity of Emissions Conditional Test Method 027 –Ammonia Slip Determination
Test Supervisor (QSTI):	Mr. Matt Savin
Test Technicians:	Mr. Derek Kopera Mr. Josh Cooper
Date(s) Tests Conducted:	September 17, 2013: Compliance and Gas RATA
Site Test Coordinator:	Charles Dufeny of Duke Energy Florida
State Regulatory Observers:	No Observers Present

Table of Contents

List of Tables

Appendices

1.0 Introduction

Duke Energy Florida, Inc. retained C.E.M. Solutions, Inc. to perform emissions testing to determine levels of particulate matter (PM), ammonia slip (NH_3), sulfuric acid mist (SAM) and visible emission (VE) from Unit 4 boiler exhaust.

The test program was used to determine the compliance status of Unit 4 in regards to its emissions limitations and standards outlined in Title V Air Operating Permit 0170004-035-AV. The test program and results are presented and discussed in this report. Target pollutants include the following:

- PM (in lb/mmBtu and lb/hr)
- VE (in percent)
- SAM (in lb/mmBtu and lb/hr)
- NH_3 (in ppmv)

Charles Dufeny of Duke Energy Florida coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection.

The test program and results are presented and discussed in this report and are summarized in Table 1.

1.1 Errors and Omissions

The initial visible emission test performed on the Unit 4 emission point showed one six-minute average above 10 percent opacity. While this is in compliance with the permitted opacity standard, it was determined that due to the Unit 4 and 5 emissions plumes combing near the stack exhaust point that an accurate visible emission reading could not be performed. In an effort to confirm compliance, the Unit 5 load was reduced to a lower level and a second V.E. was conducted on the combined plumes. The second V.E. showed that all six-minute average opacity reading were below 10 percent. Please note the V.E. reported in this document for Unit 4 is biased high due to the reading of a combined Unit 4 and Unit 5 plume.

Table 1: Compliance Test Results
Crystal River Energy Complex
Unit 4

Pollutant	RATA Result / Reported Emissions Rate	RATA Limit / Permitted Emissions Rate	Compliance Test Status (Pass/Fail)
PM	0.011 lb/mmBtu 85.4 lb/hr	0.030 lb/mmBtu 216 lb/hr	PASS
NH_3	0.4 ppmvd	5 ppmvd	PASS
SAM	0.0150 lb/mmBtu, 106.4 lb/hr	0.009 lb/mmBtu 64.8 lb/hr	Exceedence
VE	7.1 %	≤10 % except for one 6-minute period per hour of not more than 20%	PASS

2.0 Facility Description

Crystal River Unit 4 is a fossil fuel steam generator consisting of a dry bottom wall-fired boiler, rated at 760 MW, 7,200 MMBtu/hr. Primary fuel is bituminous coal or a bituminous coal and bituminous coal briquette mixture. Number 2 fuel oil and natural gas may be burned as a startup fuel and for low load flame stabilization.

2.1 Process Equipment

Fossil Fuel Steam Generator, Unit 4 is a pulverized coal, dry bottom, wall-fired boiler. Emissions are controlled from the unit with a high efficiency electrostatic precipitator, a selective catalytic reduction system and a flue gas desulfurization system. Emissions are exhausted through a 550 ft. stack.

2.2 Regulatory Requirements

The facility was required to conduct emissions testing to determine PM, NH_3, SAM and visible emissions (VE) in accordance with permit number 0170004-035-AV. The CO RATA is required to be conducted while the source is operating at 90% of the operating range. The Unit 4 emissions limitations and standards are summarized in Table 2.

Table 2: Emissions Limitations and Standards
Crystal River Energy Complex
Unit 4

Pollutant/Standard	RATA or Emission Limit
PM	0.030 lb/mmBtu 216 lb/hr
NH_3	5 ppmvd
SAM	0.009 lb/mmBtu 64.8 lb/hr
VE	≤10 %[2]

[1] The difference between monitor and reference method mean values applies to low emitters only
[2] six-minute average

3.0 Test Program/Operating Conditions

The compliance status of the Unit 4 PM, NH_3, SAM and VE emissions, in regards to Title V Operating Permit 0170004-035-AV, was tested on September 17, 2013.

For the compliance test, the Unit 4 heat input averaged 7066.0 mmBtu/hr while operating on 100 percent solid fuel, which correlates to 98.1 percent of the maximum heat input (7,200 mmBtu/hr). Soot blowing occurred during the first PM sampling run.

Unit 4 fuel flow and fuel analysis reports are located in Appendix A.

Fuel flow and fuel analysis reports were provided by Duke Energy Florida.

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

Table 3 summarizes the EPA test methods utilized to complete the test program.

Table 3: Summary of EPA Reference Methods
Crystal River Energy Complex
Unit 4

EPA Method	Description
1	Sample and Velocity Traverses for Stationary Sources
2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot)
3	Gas Analysis for Determining Dry Molecular Weight
4	Moisture Content in Stack Gases
5B	Particulate Emissions from Stationary Sources
NCASI 8A	Determination of Sulfuric Acid Mist
9	Opacity (Visible Emissions)
CTM-027	Determination of Ammonia Slip

4.1 Sample and Velocity Traverse Points

Sample and velocity traverse points were determined utilizing EPA Method 1.

The inner stack diameter, at the sample location, of the Unit 4 exhaust stack is 31’ (372”). The sample location for the stack is 10.06 diameters (312’) downstream from the nearest disturbance and 3.35 diameters upstream (104’) from the stack exit.

Four (4) ports, located 90 degrees from each other, were used at the sample location. Particulate matter and ammonia slip sampling was conducted at a total of 12 points (3 points per port). Traverse points were located at 4.4%, 14.6% and 29.6% of the inner diameter, from the inside wall of the stack. A single point, over 1 meter from the stack wall was used for sulfuric acid mist sampling. Three (3) 60-minute compliance runs were conducted. A diagram of the sample location can be viewed in Appendix C.

4.2 Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tubes)

Method 2 was used to determine the volumetric flow rate of the stack effluent gas.

Stack temperature differential pressure readings were taken with an S type pitot tube and Type K temperature sensor at each sample traverse point.

4.2.1 Method 2 Quality Assurance/Quality Control Procedures

The S type pitot tube was inspected visually and measured to meet the design specifications of EPA Method 2, for a pitot coefficient of 0.84.

The incline manometer and each leg of the pitot tube was leak checked before and immediately after each test run.

Thermocouple sensors were calibrated prior to the test program and a post test check was performed after testing completion.

The incline manometer was leveled and zeroed before each test run.

Appendix D contains the completed QA/QC forms.

4.3 CO_2 and O_2 Orsat Analyzer Method

Stack gas dry molecular weight was determined utilizing Method 3B.

Gas samples were taken at each sample traverse, stored in leak free Tedlar bags and analyzed for concentrations of Oxygen (O_2) and Carbon Dioxide (CO_2) using an Orsat analyzer.

4.3.1 Method 3B Quality Assurance/Quality Control Procedures

The orsat was leak checked prior to use and immediately following sample analysis. The sample gas was passed through the orsat system 3 times prior to analysis to ensure that a representative sample was in the orsat train. The sample was passed through the CO_2 and O_2 absorbent a minimum of 3 times for each analysis.

4.4 Moisture Content Determination

Moisture content of the stack gas was determined by Method 4.

Stack gas was sampled at each traverse point, passed through pre-weighed impingers and then through a calibrated dry gas meter. Moisture is removed from the sample gas in the pre-weighed impingers, which are submerged in an ice bath, and later analyzed for moisture weight gain. Moisture is determined based upon the amount of moisture weight gain and sample gas collected.

Field moisture data sheets are also located in Appendix E.

4.4.1 Method 4 Quality Assurance/Quality Control Procedures

The moisture sampling train was leak checked prior to each test run at approximately 15” Hg and immediately after each run at a vacuum higher than the highest vacuum recorded during the respective test run. Results are recorded on the moisture field data sheets.

Weighing to determine moisture content was conducted with a balance having an accuracy of 0.1 grams.

Gas temperature at the exit of the impingers was maintained at less than 68 degrees Fahrenheit.

4.5 Particulate Matter Determination

USEPA Method 5B was used to determine particulate emissions. Stack gas was extracted isokinetically from the gas stream; particulate emissions are measured gravimetrically by determining the amount of particulate matter collected on the glass nozzle and quartz fiber filter. The probe liner temperature was maintained at 320 degrees Fahrenheit.

Sample volume was measured by passing the gas through a set of weighed impingers used for moisture content, then passed through a calibrated dry gas meter. An S type pitot tube is attached to the probe to measure stack gas velocity and to maintain sampling conditions between 90% and 110% isokinetics. A type K temperature sensor is also attached to the probe to measure the stack gas temperature.

Isokinetic conditions were maintained throughout each test run of the test program as demonstrated in Table 4.

A minimum of 60 dscf of sample was taken each test run over a sampling period of approximately 120 minutes. Run 4 for ammonia was 60 minutes in duration.

Method 5B/CTM-027 field data sheets are located in Appendix E.

4.5.1 Sample Recovery and Analysis

After each sample run, the nozzle and filter holder ahead of the filter were brushed and rinsed with acetone. Contents were stored in a leak free container for transport to the laboratory. The impingers were weighed for increase, to the nearest 0.5 gram, to determine moisture gain.

Particulate matter was determined by drying each filter to a constant weight and recorded to the nearest 0.1 mg. Sample from the probe nozzle and filter holder were evaporated in a tared beaker at ambient temperature, oven dried at 160 ^{o}F for 6 hours and then cooled in a desiccator and weighed to a constant weight, and recorded to the nearest 0.1 mg.

Appendix E contains the analytical results for each run.

4.5.2 Quality Assurance/Quality Control Procedures

The probe nozzles were inspected and measured across three different diameters to determine the appropriate nozzle diameter.

Before and after each test run, the manometer was leveled and zeroed.
Leak checks of the sampling train were conducted before and immediately after each test run.

The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

Table 4: Isokinetic Summary
Crystal River Energy Complex
Unit 4

	% Isokinetic				
Unit	**Run 1**	**Run 2**	**Run 3**	**Average**	**Tolerance**
4	97.9	100.1	103.5	100.5	90 – 110%

4.6 Sulfuric Acid Mist (NCASI Method 8A)

NCASI Method 8A was used to determine the volume of sulfuric acid mist (SAM) present in the flue gas. Each gas stream was sampled for one hour at a constant sample rate of approximately 10 lpm[1].

The Method 8A sample train consisting of a quartz glass probe, heated to 600^{o}F $\underline{+}$ 25 ^{o}F, a heated quartz filter (600^{o}F $\underline{+}$ 25 ^{o}F) used to filter particulate, a condenser (set to a temperature of 150^{o}F $\underline{+}$ 10^{o}F) used to condense and capture H_2SO_4, and a quartz fiber filter used to capture H_2SO_4. An impinger train, composed of the following impingers, following the condenser. The first two impingers contained 100 ml of deionized water, the third impinger was empty and the final impinger contained a pre-weighed amount of indicating silica gel.

4.6.1 Sample Recovery and Analysis

A 15 minute purge with clean dry ambient air was conducted at the average sampling rate used during the sample run. After the purge, the H_2SO_4 condenser was rinsed multiple times with deionized water. The condenser wash was collected in a laboratory prepared polyethylene sample bottle. The probe and the quartz filter holder were rinsed with DI water and the rinse was discarded.

Appendix E contains the analytical results for each run.

4.6.2 Quality Assurance/Quality Control Procedures

Before and after each test run, the manometer was leveled and zeroed.
Leak checks of the sampling train were conducted before and immediately after each test run.

The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

4.7 Ammonia Slip Test

Ammonia concentrations were determined using EPA Conditional Test Method 27 (CTM-027).

---

[1] As stated in the compliance test protocol, the Method 8A testing cannot be performed isokinetically since the sample flow rates are too high. This will not allow for enough time for the thermal drop in the sample gas through the condenser.

Stack gas-samples were extracted isokinetically with the same sampling train for the Method 5B testing, for a period of 120 minutes. Gas samples were pulled from the stack through a glass nozzle and glass lined probe in to a heated filter box containing the Method 5B quartz filter. The gas was then transported, via an unheated Teflon line, to an impinger train. The impinger train consisted of two Greenburg-Smith (G-S) impingers (impingers 1 and 2) and two modified G-S impingers with the tips removed (impingers 3 and 4) all connected in series in an ice bath. Impingers 1 and 2 were charged with 100ml of 0.1N sulfuric acid (H_2SO_4) solution. The third was left empty and the fourth impinger was loaded with a pre-weighed amount of silica gel.

The volume of the liquid (catch) in each of the first three impingers was recorded for future use. Each impinger catch was transferred into individual, clean 500-ml HDPE containers. Each container was then labeled and stored on ice for shipment to the laboratory, where the samples were analyzed within 2 weeks after their collection.

An ion chromatograph equipped with a conductivity detector was used for ammonium ion separation and quantitation to analyze the samples. At a minimum, the first two impingers were analyzed for ammonia breakthrough.

Pre and post impinger weights, field data collection, and lab analysis results are presented in Appendix G.

4.7.1 Quality Assurance/Quality Control Procedures

The sample train was leak checked prior to and following each test run at or above the highest vacuum recorded during the test run in accordance with the test method.

Prior to conducting each test run, the impinger train was chilled in ice for at least 10 minutes as specified in the test method.

All sample train glassware was cleaned prior to each test run with deionized (DI) water.

Following each test run, the back half of the filter housing was rinsed with DI water and stored in the same storage container as the catch from impinger 1. Impingers 1 and 2 were rinsed with DI water after recovery and stored with the impinger catch from its perspective impinger as well. QA/QC forms can be viewed in Appendix E.

4.8 Visible Emission Determination

USEPA Method 9 was utilized to determine visible emissions.

Visible emissions observations were performed by a FDEP certified visible emissions reader. Readings were taken at 15 second intervals and reduced into six minute averages as required by the applicable EPA standard. One-sixty minute visible emissions test run was performed while the unit was operating at maximum capacity.

Method 9 data summary, field data and VE reader’s certification are located in Appendix E.

5.0 Test Results

The following presents the results of the test program. Supporting calculations and field data summaries are presented in Appendix B and E, respectively. Table 5 summarizes the results of the test program.

5.1 Particulate Matter

The three-run average particulate matter emissions during the test program was 0.011 lb/mmBtu and 85.4 lb/hr, passing the permitted emission limits of 0.030 lb/mmBtu and 216 lb/hr.

5.2 Ammonia Slip (NH_3)

The three-run average for ammonia slip during the test program was 0.4 ppmvd, passing the permitted emission limit of 5 ppmvd.

5.3 Sulfuric Acid Mist (SAM)

The three-run average for SAM during the test program was 0.0150 lb/mmBtu and 106.4 lb/hr exceeding the permitted emission limits of 0.009 lb/mmbtu and 64.8 lb/hr.

5.4 Visible Emissions

The highest six-minute average visible emissions observed from the Unit 4 stack during the 60 minute visible emission observation was 7.1 percent opacity, passing the 10 percent emission limit.

Table 5: Compliance Test Summary
Crystal River Energy Complex
Unit 4

Parameter	Run 1	Run 2	Run 3	Average	Limit
PM	0.013 102.2	0.012 92.5	0.008 61.5	0.011 lb/mmBtu 85.4 lb/hr	0.030 lb/mmBtu 216 lb/hr
NH3	1.0	0.2	0.0	0.4 ppmvd	5 ppmvd
SAM	0.0195 139.2	0.0158 113.4	0.0096 66.4	0.0150 lb/mmBtu 106.4 lb/hr	0.009 lb/mmBtu 64.8 lb/hr
VE	11.3 %*	7.1 %	N/A	7.1%	≤10 % except for one 6-minute period per hour of not more than 20%

*Run not used due to combined plumes.

Air Emissions Test Report

Completed for:

Duke Energy Florida, Inc.
Crystal River Energy Complex
Unit 5 (EU -003)

Test Report Number: 20-6542-05-001

Test Completed: September 18, 2013

C.E.M.
SOLUTIONS

1183 East Overdrive Circle • Hernando, FL 34442 • (352) 489-4337 • Fax: (352) 489-4801

Air Emissions Test Report

Duke Energy Florida, Inc.
Crystal River, Unit 5 (EU -003)
Crystal River, Florida

C.E.M. Solutions Project No.: 6542

Testing Completed: September 18, 2013

C.E.M. Solutions, Inc. Report Number: 20-6542-05-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Declaration of Conformance to ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies

C.E.M. Solutions operates in conformance with the requirements of ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies through the use of a quality system which incorporates a quality manual, internal audit system, systematic training of personnel and rigorous review of test methods and operating procedures.

Joe Conti
Quality Assurance Manager
C.E.M. Solutions

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at the Duke Energy Florida Inc. Crystal River facility conducted on September 18, 2013 are complete and accurate to the best of my knowledge.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner: Duke Energy

Address of Owner:
One Power Plaza
299 First Avenue North
St. Petersburg, FL 33701

Source Identification:
Facility: 0170004
Emissions Unit: EU-003

Location of Source: Citrus County, Florida

Type of Operation: SIC Code 4911

Tests Performed:
Method 1 – Traverse Points
Method 2 – Stack Gas Volumetric Flow and Velocity
Method 3A – Determination of Molecular Weight
Method 4 – Stack Gas Moisture Content
Method 5B – Particulate Matter
NCASI Method 8A – Sulfuric Acid Mist
Method 9 – Determination of Opacity of Emissions
Conditional Test Method 027 –Ammonia Slip Determination

Test Supervisor (QSTI): Mr. Matt Savin

Test Technicians:
Mr. Derek Kopera
Mr. Josh Cooper

Date(s) Tests Conducted: September 18, 2013: Compliance and Gas RATA

Site Test Coordinator: Charles Dufeny of Duke Energy Florida

State Regulatory Observers: No Observers Present

Table of Contents

List of Tables

Appendices

1.0 Introduction

Duke Energy Florida, Inc. retained C.E.M. Solutions, Inc. to perform emissions testing to determine levels of particulate matter (PM), ammonia slip (NH_3), sulfuric acid mist (SAM) and visible emission (VE) from Unit 5 boiler exhaust.

The test program was used to determine the compliance status of Unit 5 in regards to its emissions limitations and standards outlined in Title V Air Operating Permit 0170004-035-AV. The test program and results are presented and discussed in this report. Target pollutants include the following:

- PM (in lb/mmBtu and lb/hr)
- VE (in percent)
- SAM (in lb/mmBtu and lb/hr)
- NH_3 (in ppmv)

Charles Dufeny of Duke Energy Florida coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection.

Unit 5 was found to be in compliance with the permitted emissions limitations as summarized in Table 1. The test program and results are presented and discussed in this report.

Table 1: Compliance Test Results
Crystal River Energy Complex
Unit 5

Pollutant	RATA Result / Reported Emissions Rate	RATA Limit / Permitted Emissions Rate	Compliance Test Status (Pass/Fail)
PM	0.005 lb/mmBtu 38.5 lb/hr	0.030 lb/mmBtu 216 lb/hr	PASS
NH_3	0.0 ppmvd	5 ppmvd	PASS
SAM	0.0028 lb/mmBtu, 19.2 lb/hr	0.009 lb/mmBtu 64.8 lb/hr	PASS
VE	6.3 %	≤10 %	PASS

2.0 Facility Description

Crystal River Unit 5 is a fossil fuel steam generator consisting of a dry bottom wall-fired boiler, rated at 760 MW, 7,200 MMBtu/hr. Primary fuel is bituminous coal or a bituminous coal and bituminous coal briquette mixture. Number 2 fuel oil and natural gas may be burned as a startup fuel and for low load flame stabilization.

2.1 Process Equipment

Fossil Fuel Steam Generator, Unit 5 is a pulverized coal, dry bottom, wall-fired boiler. Emissions are controlled from the unit with a high efficiency electrostatic precipitator, a selective catalytic reduction system and a flue gas desulfurization system. Emissions are exhausted through a 550 ft. stack.

2.2 Regulatory Requirements

The facility was required to conduct emissions testing to determine PM, NH_3, SAM and visible emissions (VE) in accordance with permit number 0170004-035-AV. The CO RATA is required to be conducted while the source is operating at 90% of the operating range. The Unit 5 emissions limitations and standards are summarized in Table 2.

Table 2: Emissions Limitations and Standards
Crystal River Energy Complex
Unit 5

Pollutant/Standard	RATA or Emission Limit
PM	0.030 lb/mmBtu 216 lb/hr
NH_3	5 ppmvd
SAM	0.009 lb/mmBtu 64.8 lb/hr
VE	≤10 %[2]

[1] The difference between monitor and reference method mean values applies to low emitters only

[2] six-minute average

3.0 Test Program/Operating Conditions

The compliance status of the Unit 5 PM, NH_3, SAM and VE emissions, in regards to Title V Operating Permit 0170004-035-AV, was tested on September 18, 2013.

For the compliance test, the Unit 5 heat input averaged 6843.1 mmBtu/hr while operating on 100 percent solid fuel, which correlates to 95.0 percent of the maximum heat input (7,200 mmBtu/hr). Soot blowing occurred during the first PM sampling run.

Unit 5 fuel flow and fuel analysis reports are located in Appendix A.

Fuel flow and fuel analysis reports were provided by Duke Energy Florida.

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

Table 3 summarizes the EPA test methods utilized to complete the test program.

Table 3: Summary of EPA Reference Methods
Crystal River Energy Complex
Unit 5

EPA Method	Description
1	Sample and Velocity Traverses for Stationary Sources
2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot)
3	Gas Analysis for Determining Dry Molecular Weight
4	Moisture Content in Stack Gases
5B	Particulate Emissions from Stationary Sources
NCASI 8A	Determination of Sulfuric Acid Mist
9	Opacity (Visible Emissions)
CTM-027	Determination of Ammonia Slip

4.1 Sample and Velocity Traverse Points

Sample and velocity traverse points were determined utilizing EPA Method 1.

The inner stack diameter, at the sample location, of the Unit 5 exhaust stack is 31’ (372”). The sample location for the stack is 10.06 diameters (312’) downstream from the nearest disturbance and 3.35 diameters upstream (104’) from the stack exit.

Four (4) ports, located 90 degrees from each other, were used at the sample location. Particulate matter and ammonia slip sampling was conducted at a total of 12 points (3 points per port). Traverse points were located at 4.4%, 14.6% and 29.6% of the inner diameter, from the inside wall of the stack. A single point, over 1 meter from the stack wall was used for sulfuric acid mist sampling. Three (3) 60-minute compliance runs were conducted. A diagram of the sample location can be viewed in Appendix C.

4.2 Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tubes)

Method 2 was used to determine the volumetric flow rate of the stack effluent gas.

Stack temperature differential pressure readings were taken with an S type pitot tube and Type K temperature sensor at each sample traverse point.

4.2.1 Method 2 Quality Assurance/Quality Control Procedures

The S type pitot tube was inspected visually and measured to meet the design specifications of EPA Method 2, for a pitot coefficient of 0.84.

The incline manometer and each leg of the pitot tube was leak checked before and immediately after each test run.

Thermocouple sensors were calibrated prior to the test program and a post test check was performed after testing completion.

The incline manometer was leveled and zeroed before each test run.

Appendix D contains the completed QA/QC forms.

4.3 CO_2 and O_2 Orsat Analyzer Method

Stack gas dry molecular weight was determined utilizing Method 3B.

Gas samples were taken at each sample traverse, stored in leak free Tedlar bags and analyzed for concentrations of Oxygen (O_2) and Carbon Dioxide (CO_2) using an Orsat analyzer.

4.3.1 Method 3B Quality Assurance/Quality Control Procedures

The orsat was leak checked prior to use and immediately following sample analysis. The sample gas was passed through the orsat system 3 times prior to analysis to ensure that a representative sample was in the orsat train. The sample was passed through the CO_2 and O_2 absorbent a minimum of 3 times for each analysis.

4.4 Moisture Content Determination

Moisture content of the stack gas was determined by Method 4.

Stack gas was sampled at each traverse point, passed through pre-weighed impingers and then through a calibrated dry gas meter. Moisture is removed from the sample gas in the pre-weighed impingers, which are submerged in an ice bath, and later analyzed for moisture weight gain. Moisture is determined based upon the amount of moisture weight gain and sample gas collected.

Field moisture data sheets are also located in Appendix E.

4.4.1 Method 4 Quality Assurance/Quality Control Procedures

The moisture sampling train was leak checked prior to each test run at approximately 15" Hg and immediately after each run at a vacuum higher than the highest vacuum recorded during the respective test run. Results are recorded on the moisture field data sheets.

Weighing to determine moisture content was conducted with a balance having an accuracy of 0.1 grams.

Gas temperature at the exit of the impingers was maintained at less than 68 degrees Fahrenheit.

4.5 Particulate Matter Determination

USEPA Method 5B was used to determine particulate emissions. Stack gas was extracted isokinetically from the gas stream; particulate emissions are measured gravimetrically by determining the amount of particulate matter collected on the glass nozzle and quartz fiber filter. The probe liner temperature was maintained at 320 degrees Fahrenheit.

Sample volume was measured by passing the gas through a set of weighed impingers used for moisture content, then passed through a calibrated dry gas meter. An S type pitot tube is attached to the probe to measure stack gas velocity and to maintain sampling conditions between 90% and 110% isokinetics. A type K temperature sensor is also attached to the probe to measure the stack gas temperature.

Isokinetic conditions were maintained throughout each test run of the test program as demonstrated in Table 4.

A minimum of 60 dscf of sample was taken each test run over a sampling period of approximately 120 minutes. Run 4 for ammonia was 60 minutes in duration.

Method 5B/CTM-027 field data sheets are located in Appendix E.

4.5.1 Sample Recovery and Analysis

After each sample run, the nozzle and filter holder ahead of the filter were brushed and rinsed with acetone. Contents were stored in a leak free container for transport to the laboratory. The impingers were weighed for increase, to the nearest 0.5 gram, to determine moisture gain.

Particulate matter was determined by drying each filter to a constant weight and recorded to the nearest 0.1 mg. Sample from the probe nozzle and filter holder were evaporated in a tared beaker at ambient temperature, oven dried at 160 ^{o}F for 6 hours and then cooled in a desiccator and weighed to a constant weight, and recorded to the nearest 0.1 mg.

Appendix E contains the analytical results for each run.

4.5.2 Quality Assurance/Quality Control Procedures

The probe nozzles were inspected and measured across three different diameters to determine the appropriate nozzle diameter.

Before and after each test run, the manometer was leveled and zeroed.
Leak checks of the sampling train were conducted before and immediately after each test run.

The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

Table 4: Isokinetic Summary
Crystal River Energy Complex
Unit 5

Unit	% Isokinetic				
	Run 1	Run 2	Run 3	Average	Tolerance
4	97.9	100.1	103.5	100.5	90 – 110%

4.6 Sulfuric Acid Mist (NCASI Method 8A)

NCASI Method 8A was used to determine the volume of sulfuric acid mist (SAM) present in the flue gas. Each gas stream was sampled for one hour at a constant sample rate of approximately 10 lpm[1].

The Method 8A sample train consisting of a quartz glass probe, heated to 600°F ± 25 °F, a heated quartz filter (600°F ± 25 °F) used to filter particulate, a condenser (set to a temperature of 150°F ± 10°F) used to condense and capture H_2SO_4, and a quartz fiber filter used to capture H_2SO_4. An impinger train, composed of the following impingers, following the condenser. The first two impingers contained 100 ml of deionized water, the third impinger was empty and the final impinger contained a pre-weighed amount of indicating silica gel.

4.6.1 Sample Recovery and Analysis

A 15 minute purge with clean dry ambient air was conducted at the average sampling rate used during the sample run. After the purge, the H_2SO_4 condenser was rinsed multiple times with deionized water. The condenser wash was collected in a laboratory prepared polyethylene sample bottle. The probe and the quartz filter holder were rinsed with DI water and the rinse was discarded.

Appendix E contains the analytical results for each run.

4.6.2 Quality Assurance/Quality Control Procedures

Before and after each test run, the manometer was leveled and zeroed.
Leak checks of the sampling train were conducted before and immediately after each test run.

The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

4.7 Ammonia Slip Test

Ammonia concentrations were determined using EPA Conditional Test Method 27 (CTM-027).

---

[1] As stated in the compliance test protocol, the Method 8A testing cannot be performed isokinetically since the sample flow rates are too high. This will not allow for enough time for the thermal drop in the sample gas through the condenser.

Stack gas-samples were extracted isokinetically with the same sampling train for the Method 5B testing, for a period of 120 minutes. Gas samples were pulled from the stack through a glass nozzle and glass lined probe in to a heated filter box containing the Method 5B quartz filter. The gas was then transported, via an unheated Teflon line, to an impinger train. The impinger train consisted of two Greenburg-Smith (G-S) impingers (impingers 1 and 2) and two modified G-S impingers with the tips removed (impingers 3 and 4) all connected in series in an ice bath. Impingers 1 and 2 were charged with 100ml of 0.1N sulfuric acid (H_2SO_4) solution. The third was left empty and the fourth impinger was loaded with a pre-weighed amount of silica gel.

The volume of the liquid (catch) in each of the first three impingers was recorded for future use. Each impinger catch was transferred into individual, clean 500-ml HDPE containers. Each container was then labeled and stored on ice for shipment to the laboratory, where the samples were analyzed within 2 weeks after their collection.

An ion chromatograph equipped with a conductivity detector was used for ammonium ion separation and quantitation to analyze the samples. At a minimum, the first two impingers were analyzed for ammonia breakthrough.

Pre and post impinger weights, field data collection, and lab analysis results are presented in Appendix G.

4.7.1 Quality Assurance/Quality Control Procedures

The sample train was leak checked prior to and following each test run at or above the highest vacuum recorded during the test run in accordance with the test method.

Prior to conducting each test run, the impinger train was chilled in ice for at least 10 minutes as specified in the test method.

All sample train glassware was cleaned prior to each test run with deionized (DI) water.

Following each test run, the back half of the filter housing was rinsed with DI water and stored in the same storage container as the catch from impinger 1. Impingers 1 and 2 were rinsed with DI water after recovery and stored with the impinger catch from its perspective impinger as well. QA/QC forms can be viewed in Appendix E.

4.8 Visible Emission Determination

USEPA Method 9 was utilized to determine visible emissions.

Visible emissions observations were performed by a FDEP certified visible emissions reader. Readings were taken at 15 second intervals and reduced into six minute averages as required by the applicable EPA standard. One-sixty minute visible emissions test run was performed while the unit was operating at maximum capacity.

Method 9 data summary, field data and VE reader's certification are located in Appendix E.

5.0 Test Results

The following presents the results of the test program. Supporting calculations and field data summaries are presented in Appendix B and E, respectively. Table 5 summarizes the results of the test program.

5.1 Particulate Matter

The three-run average particulate matter emissions during the test program was 0.005 lb/mmBtu and 38.5 lb/hr, passing the permitted emission limits of 0.030 lb/mmBtu and 216 lb/hr.

5.2 Ammonia Slip (NH_3)

The three-run average for ammonia slip during the test program was 0.0 ppmvd, passing the permitted emission limit of 5 ppmvd.

5.3 Sulfuric Acid Mist (SAM)

The three-run average for SAM during the test program was 0.0028 lb/mmBtu and 19.2 lb/hr passing the permitted emission limits of 0.009 lb/mmbtu and 64.8 lb/hr.

5.4 Visible Emissions

The highest six-minute average visible emissions observed from the Unit 5 stack during the 60 minute visible emission observation was 6.3 percent opacity, passing the 10 percent emission limit.

Table 5: Compliance Test Summary
Crystal River Energy Complex
Unit 5

Parameter	Run 1	Run 2	Run 3	Average	Limit
PM	0.005 41.0	0.005 35.6	0.005 38.8	0.005 lb/mmBtu 38.5 lb/hr	0.030 lb/mmBtu 216 lb/hr
NH3	0.0	0.0	0.0	0.0 ppmvd	5 ppmvd
SAM	0.0031 21.3	0.0020 13.4	0.0033 22.9	0.0028 lb/mmBtu 19.2 lb/hr	0.009 lb/mmBtu 64.8 lb/hr
VE	6.3 %	N/A	N/A	6.3%	≤10 %

*Run not used due to combined plumes.

DUKE
ENERGY®

Robby A. Odom
Station Manager, Crystal River
Steam Plant & Fuel Operations

October 15, 2013

Submitted via email: swd_air@dep.fl.us

Mr. Erin Anthony DiBacco
Environmental Manager - Compliance & Enforcement
Florida Department of Environmental Protection
Southwest District
13051 N. Telecom Parkway
Temple Terrace, FL 33637

Dear Mr. DiBacco:

Re: **Sulfuric Acid Mist (SAM) Performance Test Submittal:**
Crystal River Facility
EU-003 & EU-004
Title V Air Operating Permit 0170004-037-AC (PSD-FL-383F)

Duke Energy is providing a copy of the SAM performance test conducted from August 26-31, 2013 for Crystal River Units 4 &5.

Please contact Jamie Hunter at (727) 820-5764 or Cynthia Wilkinson at (352) 501-5153 if you have any questions.

I hereby certify that, based on the information and belief formed after reasonable inquiry, the statements and information in the attached documents are true, accurate and complete.

Sincerely,

Robby A. Odom
Station Manager, Crystal River Steam Plant & Fuel Operations

Enclosure – SAM Performance Test Report # 20-6420-0405

Sulfuric Acid Mist Test Report

Completed for:

Duke Energy Florida, Inc.
Crystal River Energy Complex
Units 4 & 5 (EU -003 & -004)

Test Report Number: 20-6420-0405

Test Completed: August 26 - 31, 2013

C.E.M.
SOLUTIONS

Sulfuric Acid Mist Test Report

Duke Energy Florida, Inc.
Crystal River, Unit 5 (EU -003)
Crystal River, Florida

C.E.M. Solutions Project No.: 6420

Testing Completed: August 26 - 31, 2013

C.E.M. Solutions, Inc. Report Number: 20-6420-0405

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Declaration of Conformance to ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies

C.E.M. Solutions operates in conformance with the requirements of ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies through the use of a quality system which incorporates a quality manual, internal audit system, systematic training of personnel and rigorous review of test methods and operating procedures.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at the Duke Energy Florida Inc. Crystal River facility conducted on August 26 through August 31, 2013 are complete and accurate to the best of my knowledge.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner: Duke Energy

Address of Owner: One Power Plaza
299 First Avenue North
St. Petersburg, FL 33701

Source Identification: Facility: 0170004
Emissions Unit: EU-003 and EU-004

Location of Source: Citrus County, Florida

Type of Operation: SIC Code 4911

Tests Performed: Method 1 – Traverse Points
Method 2 – Stack Gas Volumetric Flow and Velocity
Method 3A – Determination of Molecular Weight
Method 4 – Stack Gas Moisture Content
NCASI Method 8A – Sulfuric Acid Mist

Test Supervisor (QSTI): Mr. Matthew Savin

Test Technicians: Mr. Derek Kopera
Mr. Josh Cooper

Date(s) Tests Conducted: August 26, 2013: 4 SAM runs on Unit 4 and 5
August 27, 2013: 2 runs on Units 4 and 5
August 28, 2013: 4 runs on Unit 4 and 5
August 29, 2013: 4 runs on Unit 4, 1 run on Unit 5
August 30, 2013: 2 runs on Unit 4
August 31, 2013: 3 runs on Unit 4

Site Test Coordinator: Cynthia Wilkinson of Duke Energy Florida

State Regulatory Observers: No Observers Present

Table of Contents

List of Tables

List of Figures

Appendices

1.0 Introduction

Duke Energy Florida retained C.E.M. Solutions, Inc. to conduct emissions testing to determine levels of sulfuric acid mist (SAM) emitted from the Unit 4 and Unit 5 boiler exhaust (emissions units EU-004 and -003 respectively) at its facility located in Crystal River, Florida.

The test program was conducted to commission the new permanent lime injection systems. Target pollutants include the following:

- SAM (in lb/mmBtu and lb/hr)

Cynthia Wilkinson of Duke Energy Florida coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection.

The Sulfuric Acid Mist emitted from Units 4 and 5 are summarized in Section 5 of this report.

2.0 Facility Description

Crystal River Units 4 and 5 are fossil fuel steam generators both consisting of dry bottom wall-fired boilers, rated at 760 MW, 7,200 MMBtu/hr. Primary fuel is bituminous coal or a bituminous coal and bituminous coal briquette mixture. Number 2 fuel oil and natural gas may be burned as a startup fuel and for low load flame stabilization.

2.1 Process Equipment

Fossil Fuel Steam Generator, Units 4 and 5 are pulverized coal, dry bottom, wall-fired boilers. Emissions are controlled from the unit with a high efficiency electrostatic precipitator, a selective catalytic reduction system and a flue gas desulfurization system. Emissions are exhausted through a 550 ft. stack.

3.0 Test Program/Operating Conditions

The test program was conducted to determine SAM emissions from August 26 to August 31, 2013.

During the test program Units 4 and 5 were run at various load and Heat Inputs. Heat Input levels were provided by Duke Energy Florida during testing.

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

Table 1 summarizes the EPA test methods utilized to complete the test program.

Table 1: Summary of EPA Reference Methods
Crystal River Energy Complex
Units 4 and 5

EPA Method	Description
1	Sample and Velocity Traverses for Stationary Sources
2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot)
3	Gas Analysis for Determining Dry Molecular Weight
4	Moisture Content in Stack Gases
NCASI 8A	Determination of Sulfuric Acid Mist

4.1 Sample and Velocity Traverse Points

Sample and velocity traverse points were determined utilizing EPA Method 1.

The inner stack diameter, at the sample location, of the Unit 5 exhaust stack is 31’ (372”). The sample location for the stack is 10.06 diameters (312’) downstream from the nearest disturbance and 3.35 diameters upstream (104’) from the stack exit.

A single point, over 1 meter from the stack wall was used for sulfuric acid mist sampling. Three (3) 60-minute compliance runs were conducted. A diagram of the sample location can be viewed in Appendix B.

4.2 CO_2 and O_2 Orsat Analyzer Method

Stack gas dry molecular weight was determined utilizing Method 3B.

Gas samples were taken at each sample traverse, stored in leak free Tedlar bags and analyzed for concentrations of Oxygen (O_2) and Carbon Dioxide (CO_2) using an Orsat analyzer.

4.2.1 Method 3B Quality Assurance/Quality Control Procedures

The orsat was leak checked prior to use and immediately following sample analysis. The sample gas was passed through the orsat system 3 times prior to analysis to ensure that a representative sample was in the orsat train. The sample was passed through the CO_2 and O_2 absorbent a minimum of 3 times for each analysis.

4.3 Moisture Content Determination

Moisture content of the stack gas was determined by Method 4.

Stack gas was sampled at each traverse point, passed through pre-weighed impingers and then through a calibrated dry gas meter. Moisture is removed from the sample gas in the pre-weighed impingers, which are submerged in an ice bath, and later analyzed for moisture weight gain. Moisture is determined based upon the amount of moisture weight gain and sample gas collected.

Field moisture data sheets are also located in Appendix D.

4.3.1 Method 4 Quality Assurance/Quality Control Procedures

The moisture sampling train was leak checked prior to each test run at approximately 15" Hg and immediately after each run at a vacuum higher than the highest vacuum recorded during the respective test run. Results are recorded on the moisture field data sheets.

Weighing to determine moisture content was conducted with a balance having an accuracy of 0.1 grams.

Gas temperature at the exit of the impingers was maintained at less than 68 degrees Fahrenheit.

4.4 Sulfuric Acid Mist (NCASI Method 8A)

NCASI Method 8A was used to determine the volume of sulfuric acid mist (SAM) present in the flue gas. Each gas stream was sampled for one hour at a constant sample rate of approximately 10 lpm. Method 8A testing cannot be performed isokinetically since the sample flow rates are too high. This will not allow for enough time for the thermal drop in the sample gas through the condenser.

The Method 8A sample train consisting of a quartz glass probe, heated to 600^oF $\pm 25\ ^oF$, a heated quartz filter ($600^oF \pm 25\ ^oF$) used to filter particulate, a condenser (set to a temperature of $150^oF \pm 10^oF$) used to condense and capture H_2SO_4, and a quartz fiber filter used to capture H_2SO_4. An impinger train, composed of the following impingers, following the condenser. The first two impingers contained 100 ml of deionized water, the third impinger was empty and the final impinger contained a pre-weighed amount of indicating silica gel.

4.4.1 Sample Recovery and Analysis

A 15 minute purge with clean dry ambient air was conducted at the average sampling rate used during the sample run. After the purge, the H_2SO_4 condenser was rinsed multiple times with deionized water. The condenser wash was collected in a laboratory prepared polyethylene sample bottle. The probe and the quartz filter holder were rinsed with DI water and the rinse was discarded.

Appendix D contains the analytical results for each run.

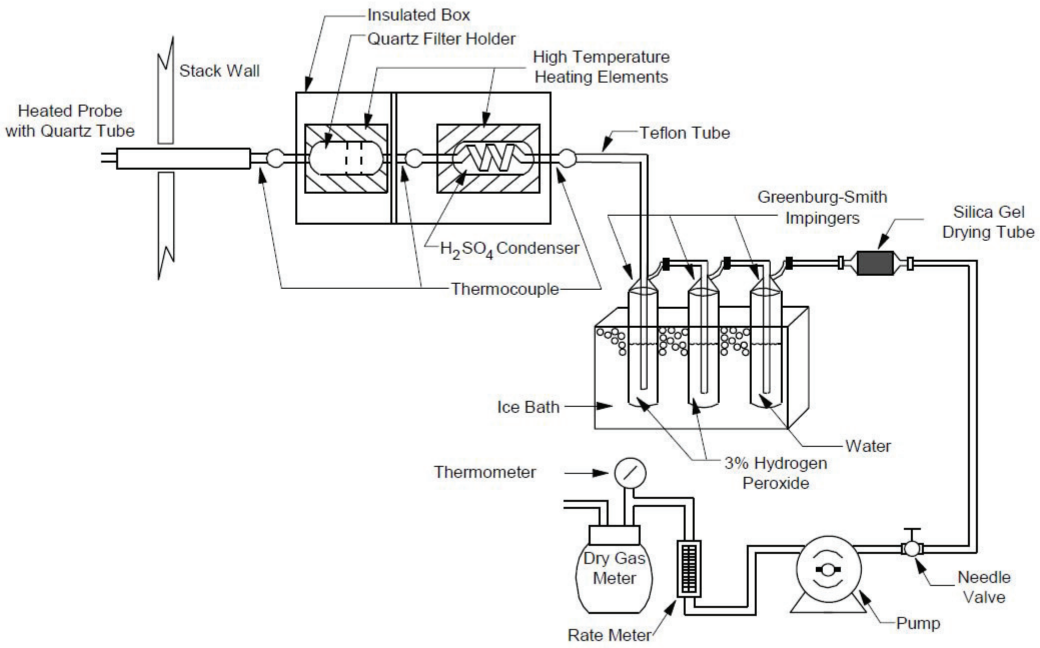
4.4.2 Quality Assurance/Quality Control Procedures

Before and after each test run, the manometer was leveled and zeroed.
Leak checks of the sampling train were conducted before and immediately after each test run.

The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix C.

Figure 1: NCASI Method 8A Sampling Train



5.0 Test Results

The following presents the results of the test program. Supporting calculations and field data summaries are presented in Appendix A and D, respectively. Tables 2 and 3 summarize the results of the test program.

Table 2: Unit 4 Compliance Test Summary
Crystal River Energy Complex
Unit 4

Run	Date	Heat Input	SAM	
			lb/mmbtu	lb/hr
1	8/26/2013	7185	0.0087	62.8
2	8/26/2013	7328	0.0082	59.8
3	8/26/2013	7478	0.0084	62.8
4	8/26/2013	7543	0.0128	96.6
5	8/27/2013	2916	0.0004	1.2
6	8/27/2013	5110	0.0074	37.6
7	8/28/2013	6825	0.0129	88.1
8	8/28/2013	6634	0.0288	191.0
9	8/28/2013	7464	0.0191	142.6
10	8/28/2013	7473	0.0192	143.4
11	8/29/2013	7404	0.0073	54.1
12	8/29/2013	7491	0.0100	75.1
13	8/29/2013	7519	0.0199	149.3
14	8/29/2013	7536	0.0066	49.4
15	8/30/2013	5220	0.0001	0.3
16	8/30/2013	3081	0.0046	14.2
17	8/31/2013	7147	0.0036	25.4
18	8/31/2013	7377	0.0039	28.5
19	8/31/2013	7375	0.0108	79.5

Table 3: Unit 5 Compliance Test Summary
Crystal River Energy Complex
Unit 5

Run	Date	Heat Input	SAM	
			lb/mmbtu	lb/hr
1	8/26/2013	7401	0.0089	65.8
2	8/26/2013	7457	0.0084	62.8
3	8/26/2013	7568	0.0110	83.1
4	8/26/2013	7616	0.0131	100.0
5	8/27/2013	2848	0.0006	1.6
6	8/27/2013	5084	0.0113	57.7
7	8/28/2013	7540	0.0052	39.1
8	8/28/2013	7761	0.0111	86.3
9	8/28/2013	7772	0.0155	120.3
10	8/28/2013	7788	0.0077	59.7
11	8/29/2013	7567	0.0056	42.3

ATTACHMENT CR-EU3-I2
COMPLIANCE ASSURANCE MONITORING
SULFURIC ACID MIST (SAM)

COMPLIANCE ASSURANCE MONITORING PLAN
(CAM PLAN)
for

SULFURIC ACID MIST (SAM)

Duke Energy Florida
Crystal River Plant Units 4 and 5

November 2013

I. EMISSION UNITS REQUIRING CAM PLANS

A. CAM Rule Applicability Definition

This Title V Operation Permit Revision application incorporates the provisions of Permit Nos. PSD-FL-383 (Project No. 0170004-037-AC and, therefore, requires changes to conditions of the current Title V Air Operation Permit No. 0170004-035-AV to incorporate these provisions. As a result of the process changes authorized under these construction permits, the development of a CAM Plan is required for emissions of sulfuric acid mist (SAM). This submittal represents Duke Energy Florida's (DEF) SAM CAM Plan for Crystal River Units 4 and 5.

The SAM emissions control equipment includes a hydrated lime based acid mist mitigation (AMM) system as the primary control. In addition, the original ammonia based AMM system remains available as a back-up control system. In order to control the amount of SAM that is exhausted through the stack, AMM systems have been installed that inject hydrated lime (primary system) or ammonia (back-up system) into the flue gas stream to reduce the concentration of SAM entering the flue gas desulfurization (FGD) system and out the stack. The objective of injecting hydrated lime into the flue gas is to react it with the SO_3 and condensed SAM to reduce the SO_3 concentration and produce solid calcium sulfate material.

The required level of AMM injection was determined during performance tests and following system tuning. Test data taken over three operating load levels (i.e., approximately 250 MW, 500 MW and full load) were used to interpolate an AMM injection curve over each unit's range of operation.

As part of the Title V renewal/revision process, EPA, through regulations adopted in Title 40, Part 64 of the Code of Federal Regulations (40 CFR 64), is requiring submittal of Compliance Assurance Monitoring (CAM) Plans. This regulation has been incorporated by reference by FDEP in Rule 62-204.800 and implemented in Rule 62-213.440.

CAM plans are required for all Title V permitted emission units using control devices to meet federally enforceable emission limits or standards with pre-control emissions greater than "major" source thresholds. The term "major" is defined as in the Title V Regulations (40 CFR 70), but applied on a source-by-source basis. However, there are some specific exemptions to the applicability of the CAM Rule.

Specifically exempted from the CAM Rule are emissions units subject to requirements under Stratospheric Ozone Regulations (40 CFR 82), the Acid Rain Program (40 CFR 72), or that are part of an emission cap included in the Title V Permit. Also exempt are emission units subject to New Source Performance Standards (40 CFR 60) and National Emission Standards for Hazardous Air Pollutants (40 CFR 63) promulgated after 11/15/1990, as these sources have equivalent monitoring requirements included as part of the standard.

B. Emissions Units Requiring CAM Plans

A review of emission units at Crystal River was conducted to determine the applicability of the CAM Rule. The evaluation process resulted in a determination that Units 4 and 5 (DEP Emission Unit ID Nos. 004 and 003) are subject to the CAM requirements. Specific exemptions to the applicability of the CAM Rule were also considered in this evaluation. However, specific to emissions of SAM, a CAM Plan is required to be submitted for Units 4 and 5.

Crystal River Unit 4 (E.U. ID No. 004)

Fossil Fuel Steam Generator Unit 4 is a pulverized coal, wet bottom, wall-fired unit. The unit is rated at 760 MW and 7,200 mmBtu/hr while burning bituminous coal with light fuel oil as a startup and low-load flame stabilization fuel. The configuration of the emissions control system, including an AMM system for control of SAM emissions, was summarized above in Section I.A. Emissions are exhausted through a 550 ft. stack.

This emission unit is regulated under Acid Rain, Phase I and II and Rule 62-210.300, F.A.C., 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; and, Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 4 began commercial operation in 1982.

Crystal River Unit 5 (E.U. ID No. 003)

Fossil Fuel Steam Generator Unit 5 is a pulverized coal, wet bottom, wall-fired unit. The unit is rated at 760 MW and 7,200 mmBtu/hr while burning bituminous coal with light fuel oil as a startup and low-load flame stabilization fuel. The configuration of the emissions control system, including an AMM system for control of SAM emissions, was summarized above in Section I.A. Emissions are exhausted through a 550 ft. stack.

This emission unit is regulated under Acid Rain, Phase I and II and Rule 62-210.300, F.A.C., 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; and, Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 5 began commercial operation in 1984.

II. CAM PLAN FOR SULFURIC ACID MIST EMISSIONS

A. Emissions Background

Compliance testing is required annually for SAM emissions for these units, as well as within 60 days of an increase of the fuel sulfur content of 0.5% or more. In addition, the AMM system injection rate is required to be continuously monitored and recorded. The injection flow rate monitoring system must be properly calibrated, operated, and maintained in accordance with Rule 62-297.520, F.A.C.

B. Emissions Units Correlations

As part of the AMM system project, DEF conducted a series of performance tests on Units 4 and 5 to determine SAM emissions rates under a variety of unit operating conditions.

The purpose of performance test program was to document the impact of the AMM system injection rate on reducing the SAM emissions and to develop a correlation curve between the injection rate, unit operating conditions/loads, and measured SAM emissions. Once the curve was developed (based upon the performance test data), it was programmed into the Distributed Control System (DCS) of each unit in order to continuously demonstrate compliance with the permitted SAM limit of 0.009 lb/mmBtu at any operating load level over each unit's range of operation (while the AMM system is operating).

The purpose of this SAM CAM Plan is to outline how the AMM system will be operated at various load levels and operating conditions, based upon the results of the AMM performance test.

C. Rationale for Selection of the Indicator Ranges

The results of the performance testing show that compliance with the permitted SAM limit of 0.009 lb/mmBtu will be met, provided that the AMM injection rate is at least 80% of the baseline amount required to react with the SAM. Taking this into account, the automated control system curve was programmed using the 100% baseline amount of injection required to control the SAM emissions.

The control system curve was set up on a "MW versus AMM lb/hr (@ 100% of the baseline value)" basis. That is, depending upon the MW currently being generated by the unit, the amount of AMM injection (in lb/hr) will be automatically adjusted, per the programmed curve. The MW and AMM injection levels are directly proportional to one another, so as the MW generated by the unit increases, the amount of AMM injection will also be increased.

Appendix A of this document illustrates the AMM system curve for firing 5 lbs SO_2/mmBtu coal for each MW value (in 50 MW increments) over the normal operating range of 250-760 MW.

Based on the above discussion, current experience suggests that, if at least 80% of the injection rate curves are maintained on a one-hour average basis, reasonable assurance will be provided that the corresponding SAM emissions standards will be met. When an excursion occurs, corrective action will be initiated as described in Table 2, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented.

III. Monitoring Approach - Table 1 (Units 4 and 5)

Table 1	**Indicator**
Indicator	AMM injection rate.
Measurement Approach	See attached injection rate curves in Appendix A
Indicator Range	An excursion is defined as an injection rate (1-hour block averaging time) that is less than 80% of the injection rate curve. Excluding periods of startup, shutdown and malfunction, pursuant to Rule 62-210.700. Periods of load change shall also be excluded. A load change occurs when the operational capacity of the unit is in the 10% to 100% capacity range, other than startup or shutdown, which exceeds 10% of the unit's rated capacity and which occurs at a rate of 0.5% per minute or more. An excursion will trigger an evaluation of operation of the boiler and the AMM system. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements.
Data Representativeness	SAM emission measurements are recorded annually at the stack.
Verification of Operational Status	NA
QA/QC Practices and Criteria	The injection flow rate monitoring system must be properly calibrated, operated, and maintained in accordance with Rule 62-297.520, F.A.C. Calibration information is recorded through a data acquisition system (DAS).
Monitoring Frequency	AMM injection rate is monitored continuously.
Data Collection Procedures	Hourly averages are recorded through the DAS. Daily reports with all hourly averages are generated.
Averaging Period	The averaging period for AMM injection rate is a 1-hour block average.

IV. Corrective Action Procedures Summary – Table 2 (Units 4 and 5)

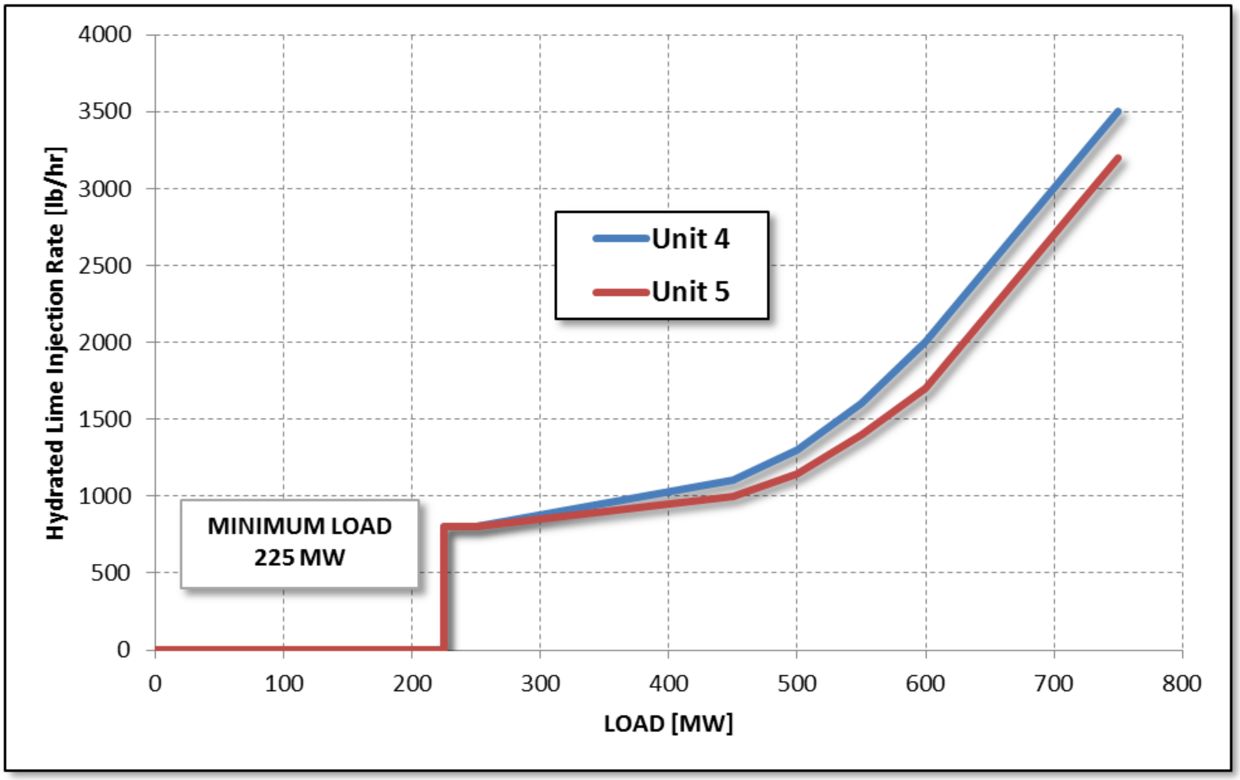
	Description
I. Initiation of Corrective Action Procedures	Corrective action shall be initiated with the discovery of a one-hour block average of the AMM injection rate less than the levels that define an excursion (as defined in Appendix A). The plant staff that made the discovery shall immediately notify the Shift Supervisor. This action describes a corrective action trigger.
II. Time of Completion of Corrective Action Procedures	Corrective actions will be taken within the time frames and in accordance with the AMM system malfunction provisions of the permit.
III. Corrective Action	The Shift Supervisor will implement the following as a corrective action. ■ Perform operational diagnostics to identify cause of the excursion; ■ If operational diagnostics indicate a malfunction of the AMM system, the reason for failure will be identified; and ■ AMM system operation will be restored to minimize SAM emissions.

APENDIX A

AMM INJECTION VERSUS LOAD CURVES

Figure 1: Hydrated Lime
Figure 2: Ammonia

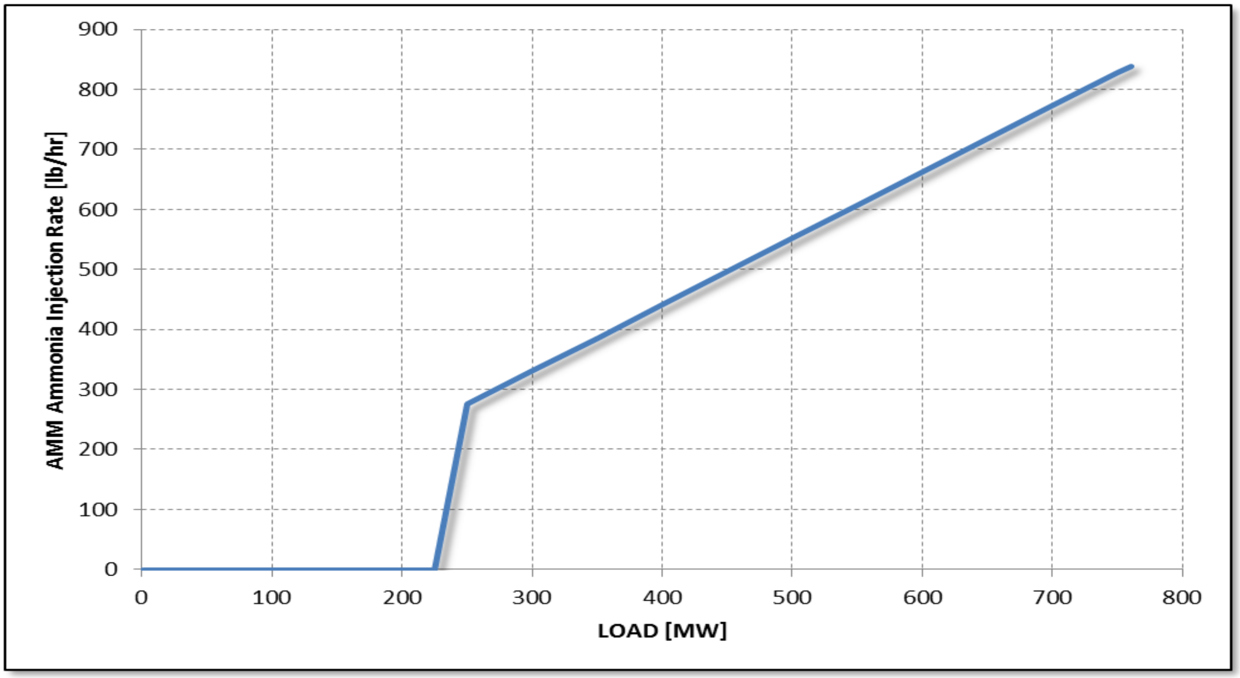
FIGURE 1 – Hydrated Lime Injection *versus* Load Curve 5 lb SO2/mmBtu Coal



LOAD	HYDRATED LIME INJECTION RATE*	
	UNIT 4	UNIT 5
[MW]	[lb/hr]	[lb/hr]
<250	800	800
400	1000	900
450	1100	1000
500	1300	1150
550	1600	1400
600	2000	1700
700	3000	2700
725	3250	2950
>750	3500	3200

**Note: All hydrated lime injection rates are based on 5 lbs SO_2/mmBtu coal. If coal sulfur levels (in terms of lbs SO_2/mmBtu) differ significantly the hydrated lime injection rate may be adjusted based on a ratio of the new sulfur level vs. the 5 lbs SO_2/mmBtu sulfur level. The only future adjustment to the curve would be down, if and when a lower sulfur coal is going to be consistently burned (this is not anticipated). In that case, the curve could be adjusted down by 20 percent, for example, for coal at a 4 lbs SO2/mmBtu sulfur level.*

FIGURE 2 – Ammonia Injection *versus* Load Curve 5 lb SO2/mmBtu Coal



MW LOAD	LB/HR INJECTION
	Ammonia*
<250	276
300	332
350	387
400	442
450	497
500	553
550	608
600	663
650	719
700	774
750	829
760	840

**Note: All ammonia injection rates are based on 5 lbs SO_2/mmBtu coal. If coal sulfur levels (in terms of lbs SO_2/mmBtu) differ significantly the hydrated lime injection rate may be adjusted based on a ratio of the new sulfur level vs. the 5 lbs SO_2/mmBtu sulfur level. The only future adjustment to the curve would be down, if and when a lower sulfur coal is going to be consistently burned (this is not anticipated). In that case, the curve could be adjusted down by 20 percent, for example, for coal at a 4 lbs SO2/mmBtu sulfur level.*

ATTACHMENT CR-EU32-I1
OPERATION AND MAINTENANCE PLAN
HYDRATED LIME STORAGE AND TRANSFER SYSTEM

HYDRATED LIME ACID MIST MITIGATION SYSTEM
OPERATING PROTOCOL

Duke Energy Florida
Crystal River Plant Units 4 and 5

November 2013

HYDRATED LIME ACID MIST MITIGATION SYSTEM
OPERATING PROTOCOL
DUKE ENERGY FLORIDA
CRYSTAL RIVER PLANT UNITS 4 AND 5
November 2013

Background

In July 2013, Duke Energy Florida, Inc. (DEF) completed the installation of a permanent hydrated lime based acid mist mitigation (AMM) system at the Crystal River Plant to reduce sulfuric acid mist (SAM) emissions on Unit #4 and Unit #5 (air construction permit #0170004-037-AC). This system replaced the originally installed ammonia based acid mist mitigation system, which has been retained as a back-up AMM system. (Note: The original ammonia based AMM system operating protocol will be followed during its use in the back-up mode.)

The hydrated lime AMM system performance testing was conducted on Crystal River Units 4 and 5 on August 26, 2013 through August 31, 2013. Additional hydrated lime AMM system tuning and optimization was conducted on October 8, 2013 and October 9, 2013. Compliance testing at Crystal River Units 4 and 5 was conducted in September and again in October, 2013. The information below includes results of all of the stack testing conducted and the operating protocol required for continuous operation of the permanent hydrated lime based AMM system.

SAM Testing Summary

The hydrated lime based AMM system performance testing for SAM emissions started on August 26, 2013 and was finished on August 31, 2013. The tuning of the hydrated lime based AMM system was conducted on October 8, 2013 and October 9, 2013. A total of 28 tests were performed on Unit 4 and a total of 23 tests were performed on Unit 5. A summary of test results is listed in Tables 1 through 4.

Annual compliance testing for Crystal River Unit 4 was conducted on September 17, 2013 and on October 10, 2013. Compliance testing for Crystal River Unit 5 was conducted on September 18, 2013 and on October 11, 2013. A summary of results for compliance testing is listed in Table 5 and Table 6. The injection rates for compliance testing were based on results from performance testing and refined following the tuning of the hydrated lime AMM system.

The operating conditions for both units were stabilized at least for 2 hours before testing began. Stack testing was performed under normal operating conditions at full load with an adequate supply of normal or routine coal (sulfur content in coal for each test is in last column of every test results table). All testing was performed by a third party contractor using independent testing equipment installed on both Units at the stack.

Table 1 – Summary of Unit #4 Performance Tests

Crystal River #4 Hydrated Lime Performance Testing					
DATE	TIME	LOAD [MW]	HYD. LIME INJECTION	STACK H_2SO_4	COAL SO_2
			[lb/hr]	[lb/mmBtu]	[lb/mmBtu]
8/26/2013	08:45-09:45	756	**2566**	**0.0087**	5.056
8/26/2013	11:30-12:30	762	**2684**	**0.0082**	5.018
8/26/2013	13:55-14:55	764	**2607**	**0.0084**	5.010
8/26/2013	16:20-17:20	764	**2319**	**0.0128**	5.079
8/27/2013	03:20-04:20	249	**1031**	**0.0004**	4.485
8/27/2013	08:20-09:20	499	**945**	**0.0074**	5.010
8/28/2013	10:30-11:30	762	**2834**	**0.0129**	4.895
8/28/2013	13:00-14:00	764	**2201**	**0.0288**	5.013
8/28/2013	15:00-16:00	759	**2179**	**0.0191**	5.113
8/28/2013	17:15-18:15	758	**2400**	**0.0192**	5.102
8/29/2013	08:45-09:45	763	**2506**	**0.0073**	5.005
8/29/2013	10:55-11:55	760	**2310**	**0.0100**	4.980
8/29/2013	13:07-14:07	763	**1642**	**0.0199**	4.958
8/31/2013	14:00-15:00	755	**2589**	**0.0108**	5.063

Table 2 – Summary of Unit #4 Tuning

Crystal River #4 Tuning					
DATE	TIME	LOAD [MW]	HYD. LIME INJECTION	STACK H_2SO_4	COAL SO_2
			[lb/hr]	[lb/mmBtu]	[lb/mmBtu]
10/8/2013	11:55-12:25	725	**3259**	**0.0044**	4.994
10/8/2013	14:30-15:00	724	**3155**	**0.0056**	5.107
10/8/2013	16:30-17:00	724	**2708**	**0.0110**	5.088
10/8/2013	17:30-18:00	724	**2587**	**0.0123**	5.009
10/9/2013	12:21-12:51	725	**3117**	**0.0056**	4.967
10/9/2013	13:55-14:25	724	**3374**	**0.0047**	4.971
10/9/2013	16:15-16:45	726	**2863**	**0.0085**	5.218
10/9/2013	17:00-17:30	724	**3007**	**0.0085**	5.281

Table 3 – Summary of Unit #5 Performance tests

Crystal River #5 Hydrated Lime Performance Testing					
DATE	TIME	LOAD [MW]	TOTAL INJECTION	STACK H_2SO_4	COAL SO_2
			[lb/hr]	[lb/mmBtu]	[lb/mmBtu]
8/26/2013	08:45-10:13	754	**2934**	**0.0089**	4.754
8/26/2013	11:30-12:30	755	**2996**	**0.0084**	4.839
8/26/2013	13:55-14:55	759	**3016**	**0.0110**	4.853
8/26/2013	16:20-17:20	764	**2569**	**0.0131**	4.682
8/27/2013	03:20-04:20	250	**1123**	**0.0006**	4.455
8/27/2013	08:20-09:20	499	**1126**	**0.0113**	4.974
8/28/2013	10:30-11:30	764	**3141**	**0.0052**	4.683
8/28/2013	13:00-14:00	763	**2819**	**0.0111**	4.735
8/28/2013	15:00-16:00	767	**2572**	**0.0155**	4.831
8/28/2013	17:15-18:15	763	**2908**	**0.0077**	4.728
8/29/2013	10:55-11:55	767	**3015**	**0.0056**	4.899

Table 4 – Summary of Unit #5 Tuning

Crystal River #5 Tuning					
DATE	TIME	LOAD [MW]	HYD. LIME INJECTION	STACK H_2SO_4	COAL SO_2
			[lb/hr]	[lb/mmBtu]	[lb/mmBtu]
10/8/2013	11:55-12:28	725	**3261**	**0.0023**	5.140
10/8/2013	13:45-14:15	725	**3195**	**0.0036**	5.035
10/8/2013	16:30-17:00	724	**2860**	**0.0044**	5.106
10/8/2013	17:30-18:00	725	**2930**	**0.0042**	5.183
10/9/2013	13:10-13:40	724	**2918**	**0.0046**	4.926
10/9/2013	14:35-15:05	725	**2907**	**0.0039**	4.890

Table 5 – Summary of Unit #4 Compliance tests

Crystal River #4 Compliance Testing*					
DATE	**TIME**	**LOAD [MW]**	**HYD. LIME INJECTION**	**STACK H_2SO_4**	**COAL SO_2**
			[lb/hr]	**[lb/mmBtu]**	**[lb/mmBtu]**
9/17/2013	09:45-10:45	762	**2947**	**0.0195**	5.001
9/17/2013	13:20-14:20	763	**2978**	**0.0158**	4.947
9/17/2013	18:00-19:00	767	**2988**	**0.0096**	3.333
10/10/2013	12:00-13:00	725	**3273**	**0.0061**	5.003
10/10/2013	15:25-16:25	726	**3288**	**0.0063**	5.062
10/10/2013	18:00-19:00	725	**3342**	**0.0061**	5.167

Table 6 – Summary of Unit #5 Compliance tests

Crystal River #5 Compliance Testing*					
DATE	**TIME**	**LOAD [MW]**	**HYD. LIME INJECTION**	**STACK H_2SO_4**	**COAL SO_2**
			[lb/hr]	**[lb/mmBtu]**	**[lb/mmBtu]**
9/18/2013	08:30-09:30	764	**3199**	**0.0031**	2.409
9/18/2013	12:25-13:25	767	**3215**	**0.0020**	3.537
9/18/2013	16:05-17:05	763	**3145**	**0.0033**	3.992
10/11/2013	11:00-12:00	725	**2968**	**0.0040**	5.206
10/11/2013	14:15-15:15	725	**2981**	**0.0038**	5.227
10/11/2013	16:50-17:50	725	**2976**	**0.0044**	5.390

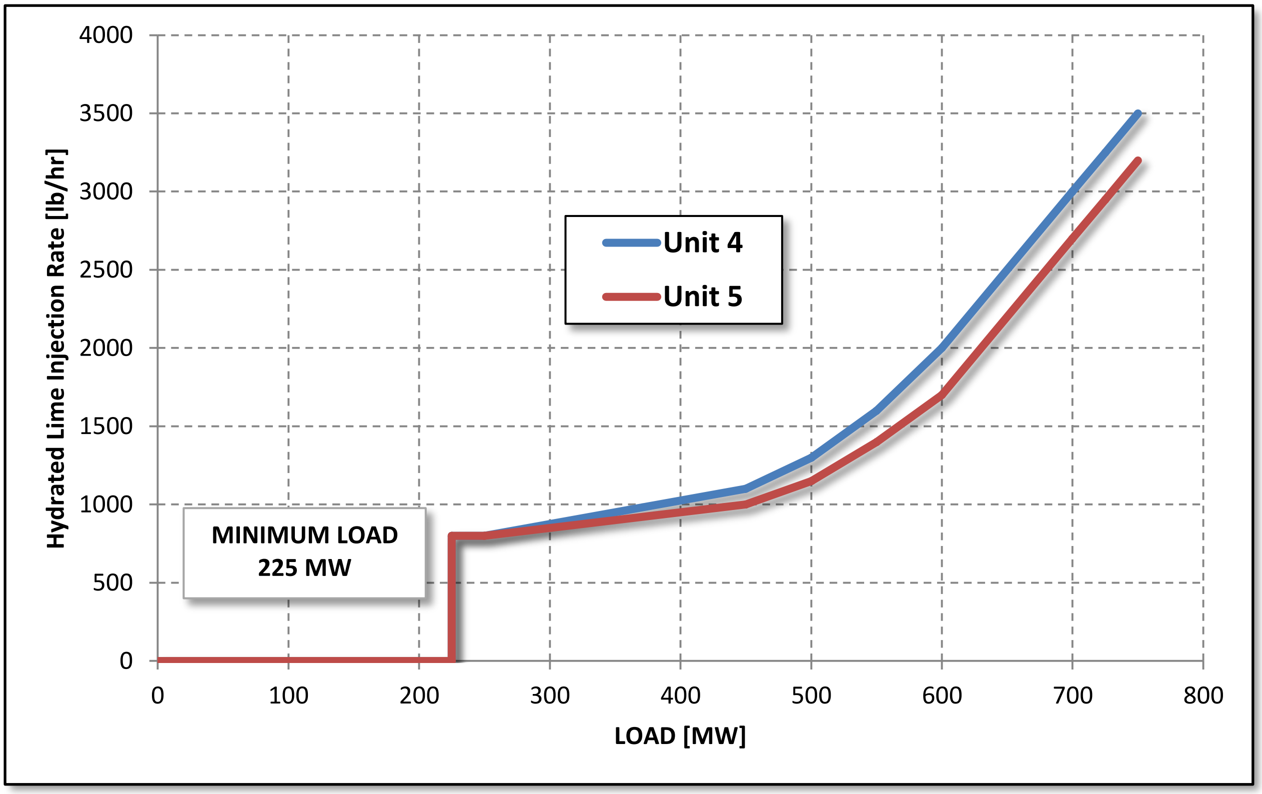
**Note: September 2013 Compliance testing was repeated in October 2013 due to several operating complications of hydrated lime AMM system during the September testing, including the boiler not being in stable conditions and variances in the coal sulfur levels during the testing.*

Operating Protocol for Continued Operation of the Permanent Hydrated Lime AMM System

Sufficient testing was conducted that shows that compliance with the SAM emission standard is achievable for all operational loads. The table below shows compliance injection rates for hydrated lime and the corresponding SAM emission levels for compliance testing (average from last 3 compliance tests).

Unit	Load	Hydrated Lime Injection Rate		STACK H_2SO_4
		Demand	Actual	
[-]	[MW]	[lb/hr]	[lb/hr]	[lb/mmBtu]
4	725	3250	3301	0.0062
5	725	2950	2975	0.0041

Based on the information from performance and compliance testing, the hydrated lime injection vs. load curve that demonstrates compliance with permitted SAM emission limit is shown below. This curve is based on fuel sulfur content equivalent to 5 lbs SO_2/mmBtu and normal operating conditions.



The above injection rate vs. load curve was implemented as part of the DCS automatic control for both units for continued operation of the permanent hydrated lime based acid mist mitigation system. The following are tabulated data for the injection curve implemented in the DCS:

LOAD	**HYDRATED LIME INJECTION RATE***	
	UNIT 4	**UNIT 5**
[MW]	[lb/hr]	[lb/hr]
<250	800	800
400	1000	900
450	1100	1000
500	1300	1150
550	1600	1400
600	2000	1700
700	3000	2700
725	3250	2950
>750	3500	3200

**Note: All hydrated lime injection rates are based on 5 lbs* SO_2*/mmBtu coal. If coal sulfur levels (in terms of lbs* SO_2*/mmBtu) differ significantly, the hydrated lime injection rate may be adjusted based on a ratio of the new sulfur level vs. the 5 lbs* SO_2*/mmBtu sulfur level.* The only future adjustment to the curve would be down, if and when a lower sulfur coal is going to be consistently burned (this is not anticipated). In that case, the curve could be adjusted down by 20 percent, for example, for coal at a 4 *lbs* SO_2*/mmBtu sulfur level.*

ATTACHMENT CR-EU32-I2
COMPLIANCE DEMONSTRATION REPORTS/RECORDS
VISIBLE EMISSIONS
OCTOBER 9-10, 2013

DUKE ENERGY®

Robby A. Odom
Station Manager, Crystal River Steam Plant
& Fuel Operations

October 30, 2013

Submitted via email: SWD_AIR@dep.state.fl.us

Mr. Erin Anthony DiBacco
Environmental Manager - Compliance & Enforcement
Florida Department of Environmental Protection
Southwest District Office
13051 North Telecom Parkway
Temple Terrace, FL 33637-0926

Re: **Submittal of Compliance Test Report**
Crystal River Facility
Facility ID: 0170004-037-AC
EU-032 (Hydrated Lime Storage and Transfer System)

Dear Mr. DiBacco,

As required by our Title V Air Construction Permit No. 017004-037-AC, Duke Energy respectfully submits this compliance test report conducted on emission point EU-032 - hydrated lime storage silo on Unit 4 and Unit 5.

These tests were conducted on October 9 and 10, 2013 in accordance with permit Specific Condition in Section 3.H.6.

The results show that compliance for the above requirements were demonstrated.

If you have any questions concerning the contents of this submittal, please contact Mr. Jamie Hunter (727) 820-5764 or Ms. Cynthia Wilkinson at (352) 501-5053.

I hereby certify that, based on the information and belief formed after reasonable inquiry, the statements and information in the attached documents are true, accurate and complete.

Sincerely,

Robby A. Odom
Station Manager, Crystal River Steam Plant & Fuel Operations

Enclosure

EPA
VISIBLE EMISSION OBSERVATION FORM 1

Method Used (Circle One) [✓ Method 9] 203A 203B Other: 30 min VE

Company Name: Duke Energy Florida Inc.

Facility Name: Crystal River Unit 5

Street Address: 15760 W. Powerline St.

City: Crystal River State: FL Zip: 34428

Process: Hydrated Lime Store 5 Unit #: Operating Mode: Unloading

Control Equipment: Baghouse Operating Mode: In Service

Describe Emission Point: Hydrated lime Storage Silo Bin Vent Unit 5

Height of Emiss. Pt. Start 120' End same

Height of Emiss. Pt. Rel. to Observer Start ~12 End ~12'

Distance to Emiss. Pt. Start ~35' End same

Direction to Emiss. Pt. (Degrees) Start 80° End same

Vertical Angle to Obs. Pt. Start 35° End same

Direction to Obs. Pt. (Degrees) Start 270° End same

Distance and Direction to Observation Point from Emission Point Start ~35' to West End same

Describe Emissions Start None. End same.

Emission Color Start N/A End N/A

Water Droplet Plume Attached ☐ Detached ☐ None ☒

Describe Plume Background Start Sky End same

Background Color Start blue End same.

Sky Conditions Start Clear End same.

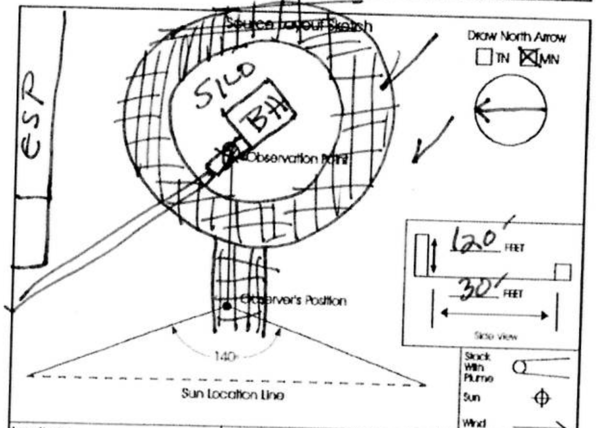
Wind Speed Start 5-10 End same

Wind Direction Start SE End Same

Ambient Temp. Start ~70° End same.

Wet Bulb Temp. unkn

RH Percent unkn



Longitude

Latitude

Declination

Additional Information: Verified unloading - SSVD Vent faces down.

Form Number

Page 1 Of 1

Continued on VEO Form Number

Observation Date 10/10/13 Time Zone ES Start Time 1032 End Time 1102

Min \ Sec	0	15	30	45	Comments
1	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
6	0	0	0	0*	*Slight wisp
7	0	0	0	0	noted
8	0	0	0	0	
9	0	0	0	0	
10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	0	0	0	0	
17	0	0	0	0	
18	0	0	0	0	
19	0	0	0	0	
20	0	0	0	0	
21	0	0	0	0	
22	0	0	0	0	
23	0	0	0	0	
24	0	0	0	0	
25	0	0	0	0	
26	0	0	0	0	
27	0	0	0	0	
28	0	0	0	0	
29	0	0	0	0	
30	0	0	0	0	

Observer's Name (Print): Cynthia Wilkinson

Observer's Signature: Date: 10/10/13

Organization: Duke Energy Florida Inc.

Certified By: ETA Date: 8-2013

EPA
VISIBLE EMISSION OBSERVATION FORM 1

Form Number
Page 1 Of 1
Continued on VEO Form Number

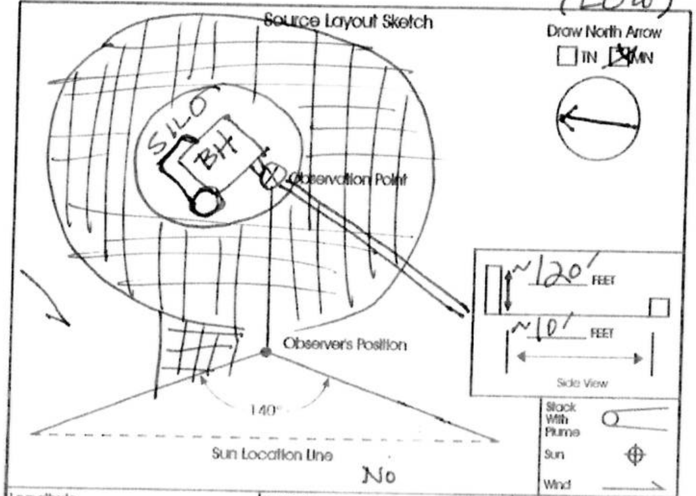
Method Used (Circle One): [✓ Method 9] 203A 203B Other: 30 min VE

Company Name: Duke Energy Florida, Inc.
Facility Name: Crystal River Unit 4
Street Address: 15760 W. Power Line St.
City: Crystal River State: FL Zip: 34428

Process: Hydrated lime Storage Unit #: 4 Operating Mode: Unloading
Control Equipment: Baghouse Operating Mode: In Service

Describe Emission Point: Hydrated lime Storage. Silo Bin Vent Unit 4
Height of Emiss. Pt.: Start 120' End 120'
Height of Emiss. Pt. Rel. to Observer: Start 12' End 12'
Distance to Emiss. Pt.: Start ~25' End ~25'
Direction to Emiss. Pt. (Degrees): Start 94° End 94°
Vertical Angle to Obs. Pt.: Start 35° End Same
Direction to Obs. Pt. (Degrees): Start 275° End 275°
Distance and Direction to Observation Point from Emission Point: Start ~30ft to WEST End Same
Describe Emissions: Start none noted End none noted
Emission Color: Start — End —
Water Droplet Plume: Attached ☐ Detached ☐ None ☒
Describe Plume Background: Start Stack/Silo structure End Same
Background Color: Start Gray/Brown (tan) End same
Sky Conditions: Start Cloudy End Same
Wind Speed: Start 5-10 End Same
Wind Direction: Start NE End same
Ambient Temp.: Start ~70° End Same
Wet Bulb Temp.: unkn
RH Percent: unkn (LOW)

Source Layout Sketch



Longitude —
Latitude —
Declination —

Additional Information: Verified off-loading started with Clean Air 550P - Mike. CW

Observation Date: 10/9/2013 Time Zone: ES Start Time: 1025 End Time: 1055

Min \ Sec	0	15	30	45	Comments
1	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
6	0	0	0	0	
7	0	0	0	0	
8	0	0	0	0	
9	0	0	0	0	
10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	Very cool
16	0	0	0	0	low humidity
17	0	0	0	0	
18	0	0	0	0	
19	0	0	0	0	
20	0	0	0	0	
21	0	0	0	0	
22	0	0	0	0	
23	0	0	0	0	
24	0	0	0	0	
25	0	0	0	0	
26	0	0	0	0	
27	0	0	0	0	
28	0	0	0	0	
29	0	0	0	0	
30	0	0	0	0	

Observer's Name (Print): Cynthia Wilkinson
Observer's Signature: Cwilk
Date: 10/9/13
Organization: Duke Energy Florida
Certified By: ETA
Date: 8-2013

VEOF1.1

At Golder Associates we strive to be the most respected global group of companies specializing in ground engineering and environmental services. Employee owned since our formation in 1960, we have created a unique culture with pride in ownership, resulting in long-term organizational stability. Golder professionals take the time to build an understanding of client needs and of the specific environments in which they operate. We continue to expand our technical capabilities and have experienced steady growth with employees now operating from offices located throughout Africa, Asia, Australasia, Europe, North America and South America.

Africa	+ 27 11 254 4800
Asia	+ 852 2562 3658
Australasia	+ 61 3 8862 3500
Europe	+ 356 21 42 30 20
North America	+ 1 800 275 3281
South America	+ 55 21 3095 9500

solutions@golder.com
www.golder.com

Golder Associates Inc.
5100 W. Lemon Street, Suite 208
Tampa, FL 33609 USA
Tel: (813) 287-1717
Fax: (813) 287-1716

Golder Associates