Orlando Utilities Commission
Curtis H. Stanton Energy Center

Facility ID No. 0950137
Orange County

Title V Air Operation Permit Renewal

Permit No. 0950137-054-AV

(Renewal of Title V Air Operation Permit No. 0950137-044-AV)

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 717-9000
Email: DARM_Permitting@dep.state.fl.us

Compliance Authority:

Central District Office

3319 Maguire Boulevard, Suite 232
Orlando, FL 32803-3767

Telephone: (407) 897-4100
Fax: (407) 412-0455
Email: DEP_CD@dep.state.fl.us

Title V Air Operation Permit Renewal

Permit No. 0950137-054-AV

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Permit No. 0950137-054-AV
Curtis H. Stanton Energy Center
Facility ID No. 0950137
Title V Air Operation Permit Renewal

The purpose of this permit is to renew the Title V air operation permit for the above referenced facility. The existing Curtis H. Stanton Energy Center (the Stanton Plant) is located in Orange County at 5100 South Alafaya Trail, Orlando. UTM Coordinates are: Zone 17, 483.6 kilometers (km) East and 3,151.1 km North. Latitude is: 28° 29' 17" North; and, Longitude is: 81° 10' 03" West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Executed in Tallahassee, Florida.

0950137-054-AV Effective Date: January 1, 2018
Renewal Application Due Date: May 20, 2022
Expiration Date: December 31, 2022

Jonathan Holtom

Digitally signed by
Jonathan Holtom, P.E.
Date: 2017.12.19
10:07:24 -05'00'

for: ______________________________

Syed Arif, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

SA/jh

Subsection A. Facility Description.

The Curtis H. Stanton Energy Center is an existing power plant (SIC No. 4911) located 144 km southeast from the Chassahowitzka National Wildlife Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area. The placard page above indicates the exact geographical coordinates. This site is comprised of multiple emissions units that are owned by multiple entities, and which are operated under two separate facility identification numbers to provide operational flexibility and better accuracy for compliance reporting purposes. Facility ID No. 0950137 is assigned to Orlando Utilities Commission (OUC) and Facility ID No. 0951378 is assigned to Southern Power Company. All the emissions units and activities addressed in the two Title V air operation permits issued to these separate operating entities are collectively considered a single facility for purposes of Title V and Prevention of Significant Deterioration (PSD) applicability. The combined facility is a major source of hazardous air pollutants (HAP).

OUC owns the land, and owns and operates most of the equipment, that comprises the Curtis H. Stanton Energy Center. Southern Power Company operates the Stanton A Combined Cycle Unit as a majority share-holder in a joint venture with Orlando Utilities Commission (OUC), Kissimmee Utilities Authority (KUA), and Florida Municipal Power Agency (FMPA).

The OUC controlled portion of the Curtis H. Stanton Energy Center consists of two fossil fuel fired steam electric generating stations, emissions unit (EU) identification (ID) No. 001 (Unit No. 1) and 002 (Unit No. 2) (including storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash) and a combined cycle combustion turbine-electrical generator (EU 037).

Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 megawatts (MW). Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 468 MW. Each boiler/steam generator is a wall-fired dry-bottom unit. Unit Nos. 1 and 2 are fired with coal. Each unit has their individual stacks. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. Units 1 and 2 are each equipped with low NO_X burners and overfire air equipment. The burner design provides accurate fuel-air ratio control and thorough mixing of fuel and air at all ratings. Unit 2 is also equipped with a selective catalytic reduction (SCR) system for further control of NO_X emissions.

Emission Units 001 and 002 are subject to compliance assurance monitoring (CAM) for particulate matter (PM) emissions controlled by an ESP. Because the continuous opacity monitoring system (COMS) is required to be used at the facility (for Phase II Acid Rain Program purposes), it must also be used as part of the CAM plan. A CAM plan is included for the ESP. See Appendix CAM.

Emission Unit 037 (Stanton Unit B) consists of: one nominal 150 megawatts (MW) General Electric 7241 FA combustion turbine-electrical generator (CTG); a supplementary fired heat recovery steam generator (HRSG) with natural gas fueled duct burners; a nominal 150 MW steam turbine generator (STG); and auxiliary equipment. The unit includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements. Stanton Unit B is equipped with dry low nitrogen oxides (NO_X) combustors as well as selective catalytic reduction (SCR) in order to control NO_X emissions to 2 parts per million by volume dry (ppmvd) at 15% oxygen (O_2) while firing natural gas. During fuel oil firing, emissions shall be held to 8 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.0015% sulfur, by weight, fuel oil, and good combustion practices are employed to control all pollutants.

Stanton Unit B is not subject to compliance assurance monitoring (CAM) because the NO_X continuous emissions monitoring system (CEMS) is used as a continuous compliance determination method. Thus, no CAM plan is included for this unit in this permit.

Also included in this permit are miscellaneous unregulated emissions units and insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
Regulated Emissions Units	
001	Fossil Fuel Fired Steam Electric Generator No. 1
002	Fossil Fuel Fired Steam Electric Generator No. 2
004	Coal Transfer Baghouse
005	Coal Crusher Building Baghouse
006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
008	Limestone Day Bin Baghouse
009	Pebble Lime Receiving Hopper Baghouse
011	Fly Ash Exhauster Filter #1 Baghouse
012	Fly Ash Exhauster Filter #2 Baghouse
013	Fly Ash Exhauster Filter #3 Baghouse
014	Fly Ash Exhauster Filter #4 Baghouse
015	Fly Ash Silo Bin Vent Filter Baghouse
016	Adipic Acid Storage Baghouse
021	Surface Coating and Solvent Cleaning
029	Fly Ash Silo Bin Vent Filter Baghouse
037	Stanton Unit B - 300 MW Combined Cycle Combustion Turbine
038	Stanton Unit B - Cooling Tower
044	Emergency Fire Pump Engines
Unregulated Emissions Units and Activities (see Appendix U, List of Unregulated Emissions Units and/or Activities)	
017	Material Handling
019	Water Treatment
020	Unconfined Emissions
022	General Purpose Engines
023	Helper Cooling Towers
024	3,740 BHP Emergency Generator
036	Inline Insertable Dust Collector
040	Natural Draft Cooling Towers

Subsection C. Applicable Regulations.

Based on the Title V air operation permit renewal application received October 2, 2017, this facility is a major source of hazardous air pollutants (HAP). Stanton Unit B is potentially subject to 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines. The existing facility is a prevention of significant deterioration (PSD) major source of air pollutants in accordance with Rule 62-212.400, F.A.C.

A summary of applicable regulations is shown in the following table.

Regulation	EU No(s).
Federal Rule Citations	
40 CFR 60, Subpart A, NSPS General Provisions	001, 002, 037
40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators	001, 002
NSPS - 40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005, adopted and incorporated by reference in Rule 62-204.800	037
40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants	004 through 007
Federal Acid Rain Program, Phase II	001, 002, 037
40 CFR 75 Acid Rain Monitoring Provisions	
40 CFR 63, Subpart A - General Provisions	001, 002, 044
40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)	044
40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units	001, 002
State Rule Citations	
Rule 62-4, F.A.C. (Permitting Requirements)	001, 002, 004 through 016, 029 and 037
Rule 62-204, F.A.C. (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference)	
Rule 62-210, F.A.C. (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms)	
Rule 62-212, F.A.C. (Preconstruction Review, PSD Review and BACT)	
Rule 62-213, F.A.C. (Title V Air Operation Permits for Major Sources of Air Pollution)	
Rule 62-214, F.A.C. (Requirements For Sources Subject To The Federal Acid Rain Program)	001, 002, 037
Rule 62-296, F.A.C. (Emission Limiting Standards)	001, 002, 004 through 016, 029
Rule 62-297, F.A.C. (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures)	001, 002, 004 through 016, 029 and 037
Rule 62-296.511, F.A.C. (Solvent Metal Cleaning)	021
PSD-FL-084	001, 002
PPS PA 81-14/SA2	01, 002

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The following conditions apply facility-wide to all emission units and activities:

FW1. Appendices. The permittee shall comply with all documents identified in Section V., Appendices, listed in the Table of Contents. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

Emissions and Controls

FW2. **Not federally Enforceable.** Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

{Permitting Note: Nothing is deemed necessary and ordered at this time.}

FW4. General Visible Emissions. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b), F.A.C.]

FW5. Unconfined Particulate Matter. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. Paving and maintenance of roads, parking areas, and yards.
b. Chemical (dust suppressants) or water application to unpaved roads, and unpaved yard areas.
c. Removal of particulate matter (PM) from roads and other paved areas to prevent re-entrainment, and from buildings or work areas to prevent airborne PM.
d. Landscaping or planting of vegetation.
e. Confining abrasive blasting where possible.
f. Other techniques, as necessary.

[Rule 62-296.320(4)(c), F.A.C.; and Application No. 0950137-054-AV received 10/2/17.]

Annual Reports and Fees

See Appendix RR, Facility-wide Reporting Requirements, for additional details and requirements.

FW6. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(3), F.A.C.]

FW7. Electronic Annual Operating Report and Title V Annual Emissions Fees. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1 of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. Each

Title V source must pay between January 15 and April 1 of each year an annual emissions fee in an amount determined as set forth in subsection 62-213.205(1), F.A.C. The annual fee shall only apply to those regulated pollutants, except carbon monoxide and greenhouse gases, for which an allowable numeric emission-limiting standard is specified in the source's most recent construction permit or operation permit. Upon completing the required EAOR entries, the EAOR Title V Fee Invoice can be printed by the source showing which of the reported emissions are subject to the fee and the total Title V Annual Emissions Fee that is due. The submission of the annual Title V emissions fee payment is also due (postmarked) by April 1st of each year. A copy of the system-generated EAOR Title V Annual Emissions Fee Invoice and the indicated total fee shall be submitted to: **Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070.** Additional information is available by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rules 62-210.370(3), 62-210.900 & 62-213.205, F.A.C.; and, §403.0872(11), Florida Statutes (2013)]

{Permitting Note: Resources to help you complete your AOR are available on the electronic AOR (EAOR) website at: http://www.dep.state.fl.us/air/emission/eaor. If you have questions or need assistance after reviewing the information posted on the EAOR website, please contact the Department by phone at (850) 717-9000 or email at eaor@dep.state.fl.us.}

FW8. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit and to the US. EPA at the address shown below within 60 days after the end of each calendar year during which the Title V air operation permit was effective. (See also Appendix RR, Conditions RR1 and RR7.) [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

U.S. Environmental Protection Agency, Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303
Attn: Air Enforcement Branch

FW9. Prevention of Accidental Releases (Section 112(r) of CAA).

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. (See paragraph e., below.)
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Division of Emergency Management, as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the Division of Emergency Management on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 27P-21, F.A.C.
d. Any required written reports, notifications, certifications, and data required to be sent to the Division of Emergency Management, should be sent to: Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9970, Fax: (850) 488-1739.
e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent electronically through EPA's Central Data Exchange system at the following address: https://cdx.epa.gov. Information on electronically submitting risk management plans using the Central Data Exchange system is available at: http://www2.epa.gov/rmp. The RMP Reporting Center can be contacted at: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.

f. Any required reports to be sent to the National Response Center, should be sent to: U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, 1200 Pennsylvania Ave. NW, Mail Code: US EPA (5101T), Washington, DC 20460, Telephone: (800) 424-8802.

g. Send the required annual registration fee using approved forms made payable to: Cashier, Division of Emergency Management, State Emergency Response Commission, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.; and, Rule 27P-21, F.A.C.]

FW10. Semi-Annual Monitoring Reports. The permittee shall monitor compliance with the terms and conditions of this permit and shall submit reports of any deviations from the requirements of these conditions at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports, including reference to the specific requirement and the duration of such deviation. All reports shall be accompanied by a certification by a responsible official, pursuant to subsection 62-213.420(4), F.A.C. (See also Conditions RR2. – RR4. of Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements related to deviations.) [Rule 62-213.440(1)(b)3.a., F.A.C.]

{Permitting Note: EPA has clarified that, pursuant to 40 CFR 70.6(a)(3), the word "monitoring" is used in a broad sense and means monitoring (i.e., paying attention to) the compliance of the source with all emissions limitations, standards, and work practices specified in the permit.}

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The specific conditions in this section apply to the following emissions unit(s):

EU No.	Brief Description
001	Fossil Fuel Fired Steam Generator No. 1
002	Fossil Fuel Fired Steam Generator No. 2

Fossil fuel fired steam generator #1 is a nominal 468 megawatt steam generator designated as Unit #1. The emission unit is fired primarily on bituminous coal with a maximum heat input of 4,800 MMBtu per hour. Stack height is 550 feet, stack exit diameter is 19.0 feet, flow rate is 1,420,000 actual cubic feet per minute (acfm) at 127 degrees Fahrenheit, stack exit velocity is 83.5 feet per second.

Fossil fuel fired steam generator #2 is a nominal 468 megawatt steam generator designated as Unit #2. The emission unit is fired primarily on bituminous coal with a maximum heat input of 4,800 MMBtu per hour. Stack height is 550 feet, stack exit diameter is 19.0 feet, flow rate is 1,310,120 acfm at 124 degrees Fahrenheit, stack exit velocity is 77.0 feet per second.

The original Permit No. PSD-FL-084 authorized the construction of Units 1 and 2 and the use of fuel oil as a secondary fuel to coal. Although not restricted in the original permit, the oil was used to ignite the coal. Permit No. 0950137-039-AC authorized the replacement of the fuel oil igniter systems with natural gas igniter systems. Fuel oil is no longer allowed as an authorized fuel in these units.

Each boiler/steam generator drives a separate steam turbine generator and each unit has an individual 550 foot exhaust stack. Particulate matter emissions generated during the operation of each unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by wet scrubber flue gas desulfurization (WFGD) equipment manufactured by Combustion Engineering.

Units 1 and 2 are each equipped with low NO_X burners and overfire air equipment. The burner design provides accurate fuel-air ratio control and thorough mixing of fuel and air at all ratings. Both an air and coal flow monitoring system are provided at each burner. Unit 2 is also equipped with a selective catalytic reduction (SCR) system for further control of NO_X emissions.

The WFGD systems for Units 1 and 2 include a dibasic acid (DBA) delivery system, and a neural network-based combustion optimization system that interfaces with the existing plant distributed control system for the purpose of optimizing boiler operations. The DBA system includes three metering pumps, one DBA storage tank, associated piping, valves, components, instrumentation and controls.

Permit No. 0950137-014-AC authorized the addition of forced oxidation to Units 1 and 2 FGD systems.

Project No. 0950137-034-AC modified the Unit 1 Flue Gas Desulfurization (FGD) system with an upgrade to the mist eliminator vanes and fixed grid wash system. This upgrade was only to the mist eliminator part of the FGD system.

Permit No. 0950137-039-AC authorized the replacement of the fuel oil igniter systems with natural gas igniter systems.

Permit No. 0950137-040-AC authorized the construction/installation, operation and maintenance of a new distribution tray or wall rings on the Unit 1 WFGD scrubber and the modification of the spray headers and nozzles and their arrangement. The permit also authorized the construction/installation, operation and maintenance of a dry sorbent injection (DSI) systems for the facility’s Unit Nos. 1 and 2 boilers. The permit also authorized the installation and operation of an SCR system on Unit 1, which has not yet been undertaken. If deemed appropriate, OUC will request an extension to the permit or re-apply for a new air construction permit that would allow for SCR installation and operation on Unit 1 in the future.

Permit No. 0950137-041-AC authorized to replacement of the high pressure and intermediate pressure portions of the Unit 2 steam turbine with improved technology. It was expected that this turbine blade replacement effort would increase the efficiency, providing an increase in power generation output capability without a corresponding increase in fuel consumption or annual generation potential.

Each boiler/steam generator (i.e., Units 1 and 2) are regulated under the federal Acid Rain Program, Phase II, adopted and incorporated by reference in Rule 62-204.800, F.A.C. These units hold ORIS code 0564.

Emission Units 1 and 2 are subject to compliance assurance monitoring (CAM) for particulate matter (PM) emissions controlled by an ESP. Because the continuous opacity monitoring system (COMS) is required to be used at the facility (for Phase II Acid Rain Program purposes), it must also be used as part of the CAM plan. *A CAM plan is included for the ESP. See Appendix CAM.*

{Permitting Notes: The emissions units are regulated under Acid Rain, Phase II; NSPS-40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7)(b)2, F.A.C.; 40 CFR 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT); and, 40 CFR 64, Compliance Assurance Monitoring (CAM). Fossil fuel fired steam generator # 1 began commercial operation on May 12, 1987; and fossil fuel fired steam generator # 2 began commercial operation on June 1, 1996.}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. As determined by the Acid Rain CEMS, the maximum allowable heat input rate for each unit, based on a 4-hour block average, is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	4,800	Coal, landfill gas from the Orange County Landfill and natural gas as supplied by commercial pipeline.
002	4,800	

[Rules 62-4.160(2), 62-204.800 and 62-210.200(PTE), F.A.C.; PSD-FL-084; Department Order Modifying Conditions of Power Plant Certification dated December 24, 1997; and, Permit No. 0950137-032-AC, Specific Condition 1.]

A.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation.

a. *Fuels.* The fuels that are allowed to be burned in this unit/these units are:
   (1) Coal, primary fuel,
   (2) Natural gas, and
   (3) Landfill gas from the Orange County Landfill.

b. *Flue Gas Desulfurization System (FGD).* No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting from the FGD system, if the bypass will cause overall SO_2 removal efficiency less than 90 percent (or 70 percent for mass SO_2 emission rates less than or equal to 0.6 lb/million Btu 30 day rolling average). The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept for a minimum of two years available for Department's inspection. The flue-gas desulfurization system and mist eliminators for Unit 2 will be maintained and operated in a manner consistent with good air pollution practice for minimizing emissions pursuant to the requirements of 40 C.F.R. 60.11(d).

[Rules 62-4.070(3) & 62-213.410, F.A.C.; 40 CFR 60.40Da; and, Permit No. PSD-FL-084]

A.4. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **A.5. – A.16.** are based on the specified averaging time of the applicable test method.

A.5. Particulate Matter (PM).

a. *Unit 1*. PM emissions shall not exceed any of the following:
   (1) 0.03 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. This standard applies at all times except during periods of startup, shutdown, or malfunction.

b. *Unit 2*. PM emissions shall not exceed any of the following:
   (1) 0.02 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. This standard applies at all times except during periods of startup, shutdown, or malfunction.
   (2) 85.7 lbs/hr.

c. *Unit 2*. Particulate Matter Less Than 10 Microns (PM_{10}) shall not exceed:
   (1) 0.02 lb/MMBtu heat input.
   (2) 85.7 lb/hr.

[Rules 62-204.800(8)(b)2., F.A.C.; 40 CFR 60.42Da; and, Permit No. PSD-FL-084/PA 81-14/SA1]

A.6. Visible Emissions. Visible emissions from Units No. 1 and 2 shall not exceed 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. [Rule 62-204.800(8), F.A.C.; 40 CFR 60.42Da; and, Permit No. PSD-FL-084]

A.7. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed any of the following:

a. *Unit No. 1*.
   (1) When Combusting solid fuel:
      (a) 1.2 lb/million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction); or,
      (b) 30 percent of the potential combustion concentration (70 percent reduction) when emissions are less than 0.60 lb/million Btu heat input; and,
      (c) 1.2 lb/MMBtu heat input, maximum two hour average, and 1.14 lb/MMBtu, heat input maximum three hour average; and,
      (d) 0.20 lb/million BTU heat input (30-boiler operating day average, as determined by CEMS) after ***January 13, 2017***.
      *{Permitting Notes: Compliance with the new SO_2 emission standard of 0.20 lb/MMBtu of heat input based on a 30-boiler operating day average for all period of operation excluding startup and shutdown shall occur after **January 13, 2017**. In addition, the more stringent SO_2 emission limit assures compliance with the less stringent, yet applicable SO_2 emission standard from NSPS 40 CFR 60, Subpart Da.}*

b. *Unit No. 2*.
   (1) When Combusting solid fuel.
      (a) 0.25 lb/million Btu (30-day rolling average) heat input; or,
      (b) 0.67 lb/million Btu (24-hour emission rate) heat input; and,
      (c) 0.85 lb/million Btu (3-hour emission rate) heat input; and,
      (d) 0.20 lb/million BTU heat input (30-boiler operating day average, as determined by CEMS) after ***January 13, 2017***.
      *{Permitting Notes: Compliance with the new SO_2 emission standard of 0.20 lb/MMBtu of heat input based on a 30-boiler operating day average for all period of operation excluding startup and shutdown shall occur after **January 13, 2017**. In addition, the more stringent SO_2 emission limit assures compliance with the less stringent, yet applicable SO_2 emission standard from NSPS 40 CFR 60, Subpart Da.}*

c. *Unit 1 and 2 Averaging Time*. Except as specified in paragraphs a.(1)(c) & (d) and b.(1)(b), (c) & (d), above, compliance with the PSD and NSPS sulfur dioxide emission limitations and percent reduction requirements are both determined on a 30-day rolling average basis.

d. Specific Conditions **A.7.a.(1)(d)** and **b.(1)(d)** shall follow the averaging times, data exclusion provision and work practice standards per the federal MATS regulation; 'boiler operating day' as defined in 40 CFR 63.10042 means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding startup and shutdown periods. It is not necessary for the fuel to be combusted the entire 24-hour period.

[Rule 62-204.800(8), F.A.C.; 40 CFR 60.43Da; PSD-FL-084/PPS PA 81-14/SA1; PA 81-14C & PA81-14SA issued 12/24/97; and, Permit No. 0950137-050-AC.]

A.8. Nitrogen Oxides. Nitrogen oxide emissions shall not exceed any of the following:

a. *Unit 1*.
   (1) When combusting bituminous coal:
      (a) 0.60 lb./million Btu heat input (30 day rolling average), nor
      (b) 0.46 lb./million Btu heat input on an annual average.

b. *Unit 2*.
   (1) When combusting bituminous coal, nitrogen oxide emissions shall not exceed 0.17 lb./million Btu heat input (30-day rolling average).

c. *Units 1 and 2*. The above standards apply at all times except during periods of startup, shutdown, or malfunction.

[Rules 62-204.800(8) & 62-214, F.A.C.; and, 40 CFR 60.44Da]

A.9. Ammonia Slip. Ammonia slip from the NO_X control system for Unit 2 shall be limited to less than 30 ppmv, uncorrected. [Permit No. PSD-FL-084 (EPA Revision Issued 3/2/93]

A.10. Carbon Monoxide (CO). As demonstrated by the required continuous emissions monitoring system (CO-CEMS), excluding allowable periods of excess emissions related to startup, shutdown and malfunction, emissions of CO shall not exceed:

a. *Unit 1*. 0.18 lb/MMBtu heat input on a 30-operating day rolling average.

b. *Unit 2*.
   (1) 0.15 lb/million Btu heat input on a 30-operating day rolling average.
   (2) 643 lb/hr.

[Permit Nos. PSD-FL-084, PA 81-14/SA1, 0950137-015-AC (PSD-FL-395), Specific Condition 9, and 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition A.3.]

A.11. Volatile Organic Compounds. Volatile Organic Compounds (VOC) emissions from Unit No. 2 shall not exceed:

a. 0.015 lb/million Btu heat input.
b. 64 lb/hr

[Permit Nos. PSD-FL-084 & PPS PA 81-14/SA1]

A.12. Sulfuric Acid Mist. Sulfuric acid mist (H_2SO_4) emissions from Unit No. 2 shall not exceed:

a. 0.033 lb/million Btu heat input.
b. 140 lb/hr.

[Permit No. PPS PA 81-14/SA1]

A.13. Beryllium. Beryllium (Be) emissions from Unit No. 2 shall not exceed:

a. $5.2x10^{-6}$ lb./million Btu heat input.
b. 0.022 lb./hr.

[Permit No. PPS PA 81-14/SA1]

A.14. Mercury. Mercury (Hg) emissions from Unit No. 2 shall not exceed:

a. $1.1x10^{-5}$ lb/million Btu heat input.

b. 0.046 lb/hr .
[Permit No. PPS PA 81-14/SA1]

A.15. Lead. Lead (Pb) emissions from Unit No. 2 shall not exceed:
a. $1.5x10^{-4}$ lb/million Btu heat input.
b. 0.64 lb/hr.
[Permit No. PPS PA 81-14/SA1]

A.16. Fluorides. Fluorides (Fl) emissions from Unit No. 2 shall not exceed:
a. $4.2x10^{-4}$ lb/million Btu heat input.
b. 1.8 lb/hr.
[Permit No. PPS PA 81-14/SA1]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C., cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

A.17. Excess Emissions Allowed. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

A.18. Excess Emissions Allowed. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

A.19. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.20. CAM Plan. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(8)(c), F.A.C. [Rules 62-204.800 & 62-213.440(1)(b)1.a., F.A.C.; and, 40 CFR 64]

Continuous Monitoring Requirements

A.21. Opacity Monitor. The permittee shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. Opacity interference exists due to water droplets in the stack from the use of an FGD system, therefore the opacity is monitored upstream of the interference (at the inlet to the FGD system). This monitoring method has been approved by the Department through permitting actions. [Rule 62-204.800(8), F.A.C.; 40 CFR 60.49Da; and, Permit No. PSD-FL-084]

A.22. Sulfur Dioxide Monitor. The permittee shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:
a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
b. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19, Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates, may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required in the preceding Specific Condition **A.22.a.**

c. Within 90 days of commencement of operations, the applicant will determine and submit to EPA and FDER the pH level in the scrubber effluent that correlates with 90% removal of the SO_2 in the flue gas (or 70% for mass SO_2 emission rates less than or equal to 0.6 lb./MMBtu). Moreover, the applicant is required to operate a continuous pH meter equipped with and upset alarm to ensure that the operator becomes aware when pH value of the scrubber effluent rises above certain limited value. The value of the scrubber pH may be revised at a later date provided notification to EPA and FDER is made demonstrating that the minimum removal will be achieved on a continuous basis. Further, if compliance data show that higher FGD performance is necessary to maintain the minimum removal efficiency limit, a different pH value will be determined and maintained.

[Rule 62-204.800(8), F.A.C.; 40 CFR 60.49Da; 40 CFR 60, Appendix A, Method 19; and, Permit No. PSD-FL-084]

A.23. Nitrogen Oxides. The permittee shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxide emissions discharged to the atmosphere. [Rule 62-204.800(8), F.A.C.; and, 40 CFR 60.49Da]

A.24. Oxygen or Carbon Dioxide. The permittee shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain optimum air/fuel ratio parameters. [Rule 62-204.800(8), F.A.C.; 40 CFR 60.49Da; and, Permit No. PSD-FL-084]

A.25. Continuous Compliance with CO limits. The permittee shall calibrate, maintain and operate a carbon monoxide (CO) continuous emissions monitor system (CO-CEMS) and record the output of the system for measuring CO emissions discharged to the atmosphere. Compliance with the 30-operating day rolling average shall be demonstrated using data collected from the required CO-CEMS. [Rule 62-4.070(3), F.A.C.; and, Permit No. 0950137-015-AC, Specific Condition 10.]

A.26. Performance Specifications and Quality Assurance. The acceptability of the CO-CEMS shall be evaluated by conducting the appropriate performance specification, as follows.

The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the expected range of emissions and corresponding emission standards.

[Rules 62-4.070(3) & 62-210.200(BACT), F.A.C.; and, Permit No. 0950137-015-AC, Specific Condition 15.]

A.27. CEMS Data Requirements for CO BACT Standard.

a. *Data Collection*: The CO-CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments.

b. *Operating Hours and Operating Days*: An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

c. *Valid Hourly Averages*: The CO-CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

(1) Hours that are not **operating** hours are not **valid** hours.

(2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is

insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

d. *Rolling 30-day average:* Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

e. *Monitor Availability*: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CO-CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-4.070(3) & 62-210.200(BACT), F.A.C.; and, Permit No. 0950137-015-AC, Specific Condition 16.]

Test Methods and Procedures

A.28. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
3A	Gas Analysis for the Determination of Emission Rate Correction Factor or Excess Air
5, 5B, modified 5, or 0010	Method for Determining Particulate Matter Emissions (All PM is assumed to be PM_{10}.)
6, 6A, 6B or 6C	Determination of Sulfur Dioxide Emissions from Stationary Sources
7, 7A, 7C, 7D or 7E	Determination of Nitrogen Oxides Emissions from Stationary Sources
8, 8A or CTM-013	Determination of Sulfuric Acid Mist Emissions
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
12	Determination of Lead Emissions
13A, 13B	Determination of Fluoride Emissions
17	Determination of In-Stack Particulate Matter (PM) Emissions
18	Determination of VOC Emissions
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Method	Description of Method and Comments
25, 25A, 25B	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
29, 101A or 30B	Determination of Hg Emissions
104	Determination of Be Emissions
108	Determination of Hg Emissions

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C.; 40 CFR 60.49Da PPS PA 81-14/SA1; PSD-FL-084; and]

A.29. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.30. Annual Compliance Tests Required. During each calendar year (January 1st to December 31st), each EU shall be tested to demonstrate compliance with the emissions standards for particulate matter, NO_X , SO_2 and visible emissions. [Rule 62-297.310(8)1., F.A.C.; and PPS PA 81-14/SA1]

A.31. Compliance Tests Prior To Renewal. Compliance tests shall be performed for both Unit 1 and Unit 2 for particulate matter, NO_X, SO_2, visible emissions and carbon monoxide once every 5 years. Compliance tests shall be performed for Unit 2 for volatile organic compounds, sulfuric acid mist, mercury, beryllium, lead and fluoride once every 5 years. The tests shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limits in Specific Conditions **A.5. – A.16.** [Rules 62-210.300(2)(a) and 62-297.310(8)(b), F.A.C.]

Recordkeeping and Reporting Requirements

A.32. Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for reporting requirements.

A.33. Fuel Sampling Record. Samples of all coal fired in the boilers shall be taken and analyzed for sulfur content, ash content, and heating value. Coal sulfur content shall be determined and recorded on a daily basis in accordance with EPA Reference Method 19. Records of all the analyses shall be kept for public inspection for a minimum of five years. [Rule 62-213.440, F.A.C. and PSD-FL-084; 0950137-043-AC, Specific Condition 4.]

A.34. CO-CEMS Annual Emissions Requirement. The owner or operator shall use data from the CO-CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit. [Rules 62-210.200, and 62-210.370(3), F.A.C.; 0950137-015-AC, Specific Condition 17.]

A.35. Excess Emissions Reporting.

a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written summary report of the incident.
b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the

BACT permit standard following the NSPS format in 40 CFR 60.7(c), Subpart A. In addition, the report shall summarize the CO-CEMS system monitor availability for the previous quarter.

c. *NSPS Reporting*: Within 30 days following the calendar quarter, the permittee shall submit the written reports required by 40 CFR 60 Subpart Da (Standards of Performance for Fossil-Fuel Fired Steam Generators) for the previous semi-annual period to the Compliance Authority.
{Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart Da, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6) and 62-212.400(BACT), F.A.C., and 40 CFR 60.7; 0950137-015-AC, Specific Condition 19.]

40 CFR 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

A.36. Subpart UUUUU Requirements. In addition to the emissions limits shown above, the permittee shall also comply with the following emissions limits no later than April 16, 2015.

a. *Filterable Particulate Matter (PM)*. Emissions of PM shall not exceed either 0.030 pound/million British thermal unit (lb/MMBtu) or 0.30 pound per megawatt-hour (lb/MWh). In lieu of the filterable PM emission limit, the permittee may select to meet a total non-Hg HAP metals emission limit of either 5.0 x 10^{-5} lb/MMBtu or 0.50 pounds per gigawatt-hour (lb/GWH). Finally, in lieu of ether filterable PM or total non-Hg HAP metals emission limits the permittee my meet the following individual HAP metal emission limits:

- Antimony (Sb) – 0.80 pounds per terra Btu (lb/TBtu) or 8.0 x 10^{-3} lb/GWh.
- Arsenic (As) – 1.1 lb/TBtu or 0.020 lb/GWh.
- Beryllium (Be) – 0.20 lb/TBtu or 2.0 x 10^{-3} lb/GWh.
- Cadmium (Cd) – 0.30 lb/TBtu or 3.0 x 10^{-3} lb/GWh.
- Chromium (Cr) – 2.8 lb/TBtu or 0.030 lb/GWh.
- Cobalt (Co) – 0.80 lb/TBtu or 8.0 x 10^{-3} lb/GWh.
- Lead (Pb) – 1.2 lb/TBtu or 0.020 lb/GWh.
- Manganese (Mn) – 4.0 lb/TBtu or 0.050 lb/GWh.
- Nickel (Ni) – 3.5 lb/TBtu or 0.040 lb/GWh.
- Selenium (Se) – 5.0 lb/TBtu or 0.060 lb/GWh.

b. *Hydrogen Chloride (HCl)*. Emissions of HCl shall not exceed either 2.0 x 10-3 lb/MMBtu or 0.020 lb/MWh. In lieu of HCl emission limit, the permittee may select to meet a SO_2 emission limit of either 0.20 lb/MMBtu or 1.5 lb/GWH.

c. *Mercury (Hg)*. Emissions of Hg shall not exceed either 1.2 lb/TBtu (30day rolling average) or 0.013 lb/GWh. Also, 1.0 lb/TBtu with both units on a 90 day rolling average.

Compliance with the above emissions limits shall be demonstrated pursuant to one of the available options specified in 40 CFR 63, Subpart UUUUU (see attached Appendix NESHAP Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units). The permittee shall also comply with the recordkeeping and reporting requirements specified Subpart UUUUU, as applicable. [40 CFR 63.9991 and Table 2 to Subpart UUUUU]

{Permitting Note: Power output is on a gross basis for compliance with applicable emission limits. You may not use the alternate SO_2 emission limit in lieu of the HCl limit if your Electric Utility Steam Generating Unit does not have some form of FGD system and SO_2 CEMS installed.}

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Subsection B. Material Handling Systems and Baghouses

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
004	Coal Transfer Baghouse
005	Coal Crusher Building Baghouse
006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
008	Limestone Day Bin Baghouse
009	Pebble Lime Receiving Hopper Baghouse
011	Fly Ash Exhauster Filter #1 Baghouse
012	Fly Ash Exhauster Filter #2 Baghouse
013	Fly Ash Exhauster Filter #3 Baghouse
014	Fly Ash Exhauster Filter #4 Baghouse
015	Fly Ash Silo Bin Vent Filter Baghouse
016	Adipic Acid Storage Baghouse
029	Fly Ash Silo Bin Vent Filter Baghouse

Emissions of particulate matter resulting from the handling of coal, lime, limestone and fly ash are controlled by the multiple baghouses listed above. Fly ash silos handle fly ash from Steam Generators No. 1 and No. 2 respectively. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silos and then is gravity fed by tubing into totally enclosed tanker trucks. Particulate matter (PM) emissions generated from material handling by silo loading and unloading to a tanker truck are controlled by baghouses, in addition to reasonable precautions to prevent unconfined emissions. Emissions units 004 - 007 are subject to the applicable requirements under 40 CFR 60, Subpart Y - Standards of Performance for Coal Preparation Plants, since the facility has coal processing and conveying equipment (including breakers and crushers) and the facility commenced construction after October 24, 1974, per 40 CFR 60.250.

{Permitting Notes: The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. Because the potential to emit PM is below the major source threshold, these emissions units are not subject to CAM.}

Essential Potential to Emit (PTE) Parameters

B.1. Hours of Operation. Fly ash silos are each allowed to operate continuously (i.e., 8,760 hrs./yr.). [Rule 62-210.200, F.A.C., Definition (PTE)]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **B.2 – B.3.** are based on the specified averaging times of the applicable test method.

B.2. Particulate Matter and Visible Emissions. Particulate emissions from coal, lime, limestone and fly ash handling systems shall be limited to 0.02 gr./acf. A visible emission reading of 5% opacity or less may be used to establish compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr./acf emission limit is being violated. However, a visible emission reading greater than 5% opacity will require the permittee to perform a stack test for particulate emissions. [Permit No. PPS PA 81-14/SA1]

B.3. Fugitive Emissions. The following requirements shall be met to minimize fugitive dust emissions from the coal storage and handling facilities, the limestone storage and handling facilities, haul roads and general plant operations:

a. All conveyors and conveyor transfer points will be enclosed to preclude PM emissions (except those directly associated with the coal stacker/reclaimer and the emergency stockout facilities for which enclosure is operationally infeasible). All coal and limestone conveyors not underground or within buildings will be enclosed (roof and sides) with steel grating or concrete floors (except the stacker/reclaimer which will have windscreen protection);
b. Inactive coal storage piles will be shaped, compacted and oriented to minimize wind erosion.
c. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent except when adding, transferring and/or removing coal from the coal pile during which the opacity allowed shall be 20%.
d. The limestone handling receiver hopper will be equipped with water spray dust control facilities. Limestone conveyors not underground or within buildings will be enclosed with open grating floors (except where concrete floors are provided over roads or other facilities). Limestone day silos and associated transfer points will be maintained at negative pressures during filling operations with the exhaust vented to a control system. Lime will be handled with a totally enclosed pneumatic system. Exhaust from the lime silos during filling will be vented to a collector system.
e. The fly ash handling system (including transfer and silo storage) will be totally enclosed and vented (including pneumatic system exhaust) through fabric filters. Particulate emissions from fly ash handling system shall be limited to 0.02 gr./acf. A visible emission reading of 5% opacity or less may be used to establish compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr./acf emission limit is being violated. However, a visible emission reading greater than 5% opacity will require the permittee to perform a stack test for particulate emissions.

[Permit No. PSD-FL-084]

{Permitting Note: The requirements listed above apply to the conveyors, drop points and handling equipment that are controlled by the baghouses regulated in this subsection, as well as to the haul roads and general plant operations.}

Test Methods and Procedures

B.4. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
5	Method for Determining Particulate Matter Emissions (All PM is assumed to be PM_{10}.)
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Permit Nos. PPS PA 81-14/SA1 & PSD-FL-084]

B.5. Annual Compliance Tests. During each calendar year (January 1st to December 31st), the permittee shall have a formal visible emissions compliance test conducted on each silo baghouse for a minimum period of 30 minutes. If a visible emission reading greater than 5% opacity is observed, the permittee shall perform a stack test for particulate emissions before the end of the calendar year, or within 60 days, whichever is later. [Rules 62-297.310(5)(b) & 8(a), F.A.C.; and, Permit No. PPS PA 81-14/SA1]

{Permitting Note: It is presumed that the threshold of visibility for opacity is equal to 5%.}

B.6. Visible Emissions. Compliance with the opacity limit listed in **B.2**. will be determined by EPA Reference Method 9. [Permit No. PPS PA 81-14/SA1]

Recordkeeping and Reporting Requirements

B.7. Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for reporting requirements. [Rule 62-213.440, F.A.C.]

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This section of the permit addresses the following emissions unit.

EU No.	Brief Description
037	Stanton Unit B - 300 MW Combined Cycle Combustion Turbine

Unit B consists of: one nominal 150 megawatt (MW) General Electric 7241 FA combustion turbine-electrical generator (CTG); a supplementary fired heat recovery steam generator (HRSG) with natural gas fueled duct burners (DB); and a nominal 150 MW steam turbine generator (STG) for an overall nominal rating of 300 MW. This unit includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements. The stack height is 165 feet, exit diameter is 20 feet, stack exit temperature is 262 (gas) and 272 (oil) degrees Fahrenheit (F) and volumetric flow rate is 1,239,934 (gas) and 1,031,061 (oil) actual cubic feet per minute (acfm).

Unit B uses natural gas as the primary fuel, and Ultra Low Sulfur Diesel (ULSD) fuel oil (0.0015% Sulfur) as a backup fuel. Carbon monoxide (CO) and particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions are minimized by the efficient combustion of natural gas and ULSD fuel oil at high temperatures. Emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2) are minimized by firing natural gas and ULSD fuel oil. Nitrogen oxide (NO_X) emissions are reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.

Unit B is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same CEMS as well as CO CEMS are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content are monitored as a diluent gas.

Unit B is subject to the requirements of Phase II of the federal Acid Rain Program. This unit holds ORIS code 0564. This emissions unit is not subject to compliance assurance monitoring (CAM) because the NO_X CEMS is used for continuous compliance determination. Thus, no CAM plan is included in this permit for this unit. Unit B began commercial operation on October 27, 2009.

{*Permitting Note: This emissions unit and its auxiliary equipment were reviewed under the rules for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. Permit No. 0950137-020-AC/PSD-FL-373A was issued on May 9, 2008. Best Available Control Technology (BACT) determinations were made for nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfuric acid mist (SAM), and sulfur dioxide (SO_2)in accordance with Rule 62-210.200 (Definitions). This unit is also regulated under Rule 62-212.400 (PSD), F.A.C., Acid Rain-Phase II and 40 CFR 60 - NSPS, Subpart KKKK. Because the existing facility is a major source of hazardous air pollutants (HAP), Unit B is potentially subject to 40 CFR 63 - NESHAP, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. However, the applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines such as planned for this project.*}

General

C.1. BACT Requirements. Unit B is subject to BACT requirements for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.1.]

C.2. NSPS Requirements. Unit B shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the NSPS for Subpart KKKK. Some separate reporting and monitoring may be required by these subparts.

a. Subpart A, General Provisions, including:
   (1) 40 CFR 60.7, Notification and Record Keeping

(2) 40 CFR 60.8, Performance Tests
(3) 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
(4) 40 CFR 60.12, Circumvention
(5) 40 CFR 60.13, Monitoring Requirements
(6) 40 CFR 60.19, General Notification and Reporting Requirements

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

[Rule 62-204.800, F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.2.]

Equipment

C.3. CTG. The permittee is authorized to tune, operate, and maintain one natural gas-fueled GE Model 7FA CTG with a nominal generating capacity of 150 MW. The CTG is equipped with Dry Low NOx (DLN) combustors, an inlet air filtration system with evaporative coolers, power (steam) augmentation capability and the capability to fire ULSD fuel oil. The unit shall be equipped with the SpeedtronicTM Mark VI (or more recent version) automated gas turbine control system. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.3.]

C.4. HRSG. The permittee is authorized to operate, and maintain one HRSG with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator with a nominal generating capacity of 150 MW. The HRSG is equipped with supplemental gas-fired DB having a nominal heat input rate of 531 MMBtu (higher heating value (HHV)). [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.4.]

Control Technology

C.5. DLN Combustion. The permittee shall operate and maintain the GE DLN 2.6 combustion system (or better) to control NO_X emissions from the CTG when firing natural gas. The system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.5.]

C.6. Wet Injection. The permittee shall operate, and maintain a wet injection system (water or steam) to reduce NO_X emissions from the CTG when ULSD fuel oil is fired. The system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.6.]

C.7. Selective Catalytic Reduction (SCR) System. The permittee shall, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or ULSD fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.
Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.7.]

Performance Restrictions

C.8. Capacity – CTG. The nominal heat input rating excluding steam for power augmentation of the CTG is 1,765 MMBtu per hour when firing natural gas and 1,935 MMBtu per hour when firing ULSD fuel oil based on a compressor inlet air temperature of 70° F, the higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall have provided manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing and shall provide updated curves following any maintenance or tuning sessions that results in a change to the previously submitted curves. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.8.]

C.9. Capacity - DB. The nominal heat input rating of the DB located within the HRSG is 531 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the DB. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.9.]

C.10. Hours of Operation. The gas turbine may operate throughout the year (8,760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.10.]

C.11. Authorized Fuels. The CTG turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. The CTG shall fire no more than 1000 hours of ULSD fuel oil, regardless of mode, during any calendar year. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.11.]

C.12. Methods of Operation. Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

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

b. *Pseudo Simple Cycle Operation*. The CTG/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

c. *Evaporative Cooling*. Evaporative cooling is the passing of gas turbine compressor inlet air through a wetted media, which reduces the inlet air temperature through evaporative cooling. Lower compressor inlet temperatures result in more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Evaporative cooling may be implemented at ambient temperatures of 60° F or higher.

d. *Power Augmentation (PA)*. PA provides additional direct, shaft-driven electrical power by increasing the mass flow rate through the compressor by the injection of steam. Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine.

e. *DB Firing*. The HRSG system may fire natural gas in the DB to provide additional steam-generated electrical power.

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.12.]

Emissions Standards

C.13. Emission Standards. Emissions from the CTG/HRSG system shall not exceed the following standards:

Pollutant	Fuel	Method of Operation	Annual Stack Tests 3-Run Average		CEMS Block Average
			ppmvd @15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CTG)	8.0	36.7	8.0, 24-hr
	Gas	CTG Normal	4.1	15.9	
		CTG & Duct Burner (DB)	7.6	37.2	
		CTG Low Load	N/A	N/A	
		CTG & PA with or w/o DB	N/A	N/A	14, 24-hr
	Oil/Gas	All Modes	N/A	N/A	6.0, 12-month
NO_X [b]	Oil	CTG	8.0	60.3	8.0, 24-hr
	Gas	CTG Normal	2.0	12.7	2.0, 24-hr
		CTG & DB	2.0	16.1	
		CTG & PA with or w/o DB	N/A	N/A	
$PM/PM_{10}/PM_{2.5}$ [c]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia [e]	Oil/Gas	CTG, All Modes	5.0	N/A	N/A

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the PA mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content as detailed in Specific Condition **C.32.** Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed Specific Condition **C.32.**

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 70 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.13.]

Excess Emissions

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. C.13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

C.14. Operating Procedures. BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the CTG, DB, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) & 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.14.]

C.15. Definitions.

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

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

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

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.15.]

C.16. Excess Emissions Prohibited. Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.16.]

C.17. Alternate Visible Emissions Standard. Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.17.]

C.18. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the CTG/HRSG system, excess NO_X and CO emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. *CTG/HRSG System Cold Startup.* For cold startup of the CTG/HRSG system, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed six hours (up to 360 minutes) during the startup period. A "cold startup of the CTG/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.
{Permitting Note: During a cold startup of the steam turbine system, the CTG/HRSG system is brought on line at low load to gradually increase the temperature of the steam turbine generator (STG) and prevent thermal metal fatigue}

b. *CTG/HRSG System Warm Startup.* For warm startup of the CTG/HRSG system, excess NO_X and CO emissions shall not exceed four hours (up to 240 minutes) during the startup period. A "warm startup of the CTG/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *CTG/HRSG System Hot Startup*. For hot startup of the CTG/HRSG system, excess NO_X and CO emissions shall not exceed 2 hours (up to 120 minutes) during the startup period. A "hot startup of the CTG/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine for 8 hours or less.

d. *Documented Malfunctions During Startup Periods.* In the event that a documented malfunction occurs during a startup period, the excess emissions period for the startup may be extended for up to 2 additional hours (as provided above) for purposes of resolving the malfunction, as long as the excess emissions period due to a malfunction has not been previously consumed during the current 24-hour period.

e. *Shutdown.* For shutdown of the combined cycle operation, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed three hours (up to 180 minutes) during the shutdown period.

f. *Fuel Switching.* Excess NO_X and CO emissions due to oil-to-gas or gas-to-oil fuel switching shall not exceed 2 hours (up to 120 minutes) each, respectively, in a 24-hour block period.

[Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.18. and 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.3.]

C.19. Ammonia Injection. Ammonia injection shall begin as soon as operation of the CTG/HRSG SCR emission control system achieves the operating parameters specified by the SCR manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG/HRSG system including the pollution control equipment. [Rules 62-212.400(BACT) and 62-210.700, F.A.C.; and, Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.19. & 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.4.]

C.20. DLN Tuning. CEMS data collected during major DLN or wet injection tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after a combustor change-out, a major repair or maintenance to a combustor, as required to maintain compliance, or other circumstances identified or requested by the equipment vendor. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.20. & 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.5.]

Emissions Performance Testing

C.21. Test Methods. Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. This is an EPA conditional test method. The minimum detection limit shall be 1 ppm. Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

Method	Description of Method and Comments
10	Determination of Carbon Monoxide Emissions from Stationary Sources. The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 & 62-297.100, F.A.C.; 40 CFR 60, Appendix A; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.21.]

C.22. Subsequent Compliance Test Determinations After Major Replacement or Major Repair. The Department may, for good reason, require the permittee to conduct additional stack tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. When requested, the CTG shall be stack tested to demonstrate compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after bringing the unit back on-line. The unit shall be tested when firing natural gas, when using the duct burners, and when firing ULSD fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. [Rule 62-297.310(8)(b), F.A.C.; 40 CFR 60.8.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.22.]

C.23. Annual Compliance Tests. During each calendar year (January 1st to December 31st) in which the combustion turbine unit operates for more than 400 hours, the CTG shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_X standards. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. If normal operation on fuel oil is less than 400 hours per calendar year, then annual compliance testing on fuel oil is not required for that year. [Rules 62-212.400 (BACT) & 62-297.310(8), F.A.C.; and, Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.23., 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.6. & 0950137-043-AC, Specific Condition 5.]

C.24. Compliance Tests Prior to Renewal. Prior to permit renewal stack testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during each performance test. The test shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the ammonia limit specified in Specific Condition **C.13.** [Rule 62-213.440(1)(b), F.A.C., and, Permit Nos. 0940137-020-AC/PSD-FL-373A, Specific Condition 28. & 0950137-043-AC, Specific Condition 5.]

C.25. Continuous Compliance. The permittee shall demonstrate continuous compliance with the 24-hour and 12-month average CO emissions standards, and with the 24-hour average NO_X emission standard based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. See Appendix CEMS for additional requirements. [Rule 62-212.400 (BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.24.]

C.26. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition **C.30.** and **C.31.**, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.25.]

Continuous Monitoring Requirements

C.27. CEM Systems. The permittee shall calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

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

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

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

[Rule 62-213.440(1), F.A.C., and Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.26.]

C.28. CEMS Data Requirements.

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

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

c. *24-hour Block Averages*. A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For the CEMS compliance demonstration, hourly average emission rates calculated during episodes of startup, shutdown, malfunction, DLN tuning, or fuel switching subject to the provisions of Conditions 19 and 20 of this section will exclude the one-minute average data corresponding to emissions in excess of the emissions limiting standards during these episodes. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block.
{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages.* Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

e. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the one minute average CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Conditions 18 and 20 of this section. All periods of one minute average data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

[Rule 62-212.400(BACT), F.A.C.; and, Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.27. & 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.7.]

C.29. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that is consistent with the documented flow rate for the combustion turbine load condition. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.28.]

Records and Reports

C.30. Monitoring of Capacity. The permittee shall monitor and record the operating rate (in units of MMBtu/hr) of the CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.29.]

C.31. Monthly Operations Summary. By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.30.]

C.32. Fuel Sulfur Records. The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

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

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

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rule 62-4.160(15), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.31.]

C.33. Emissions Performance Test Reports. A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(10)(a), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A ,Specific Condition A.32.]

C.34. Excess Emissions Reporting.

a. *Malfunction Notification.* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of:

the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report:* Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Excess emissions that occur during periods of startup, shutdown, malfunction, fuel switching and DLN tuning shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit for those hourly periods during which they occur and not for the entire averaging period. These hourly excess emissions periods shall then be excluded from the block averages calculated to demonstrate compliance with the emissions limits specified within this permit. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports*. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.
{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 & 60.332(j)(1); and, Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.33. & 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.8.]

C.35. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(2), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.34.]

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Subsection D. Unit B Cooling Tower

This section of the permit addresses the following emissions unit.

EU No.	Brief Description
038	Cooling Tower – consisting of six cells with six individual exhaust fans

This emissions unit is a six-cell mechanical draft cooling tower, equipped with drift eliminators, that serves Stanton Unit B. This unit commenced operation on October 27, 2009.

{*Permitting Note: This emissions unit was reviewed under the rules for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. This unit is regulated under Rule 62-04.070(3), and Rule 62-212.400, F.A.C.}*

Equipment

D.1. Cooling Tower. The permittee is authorized to operate a 6-cell wet evaporative mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 56,000 gallons per minute; drift eliminators; and a drift rate of no more than 0.0005 percent of the circulating water flow. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition B.1.]

Emissions and Performance Requirements

D.2. Drift Rate. Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition B.2.]

{Permitting Note: This work practice standard is established as BACT for $PM/PM_{10}/PM_{2.5}$ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 3 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

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Subsection E. Non-Emergency Fire Pump Engines

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
044	Two 277 HP Non-Emergency Diesel Fire Pumps

Emissions Unit 044 consists of two diesel fuel-fired reciprocating internal combustion engine-driven non-emergency fire pumps. These fire pumps are typically only used for emergency purposes, but since the engines are more than able to meet the emissions limits for existing non-emergency engines without add-on oxidation catalyst, OUC is choosing to comply with the non-emergency requirements 40 CFR 63, Subpart ZZZZ, to lessen the record keeping burden associated with the limited emergency use provisions of the federal rule.

The following table provides important details for this engine:

Engine Identification	Engine Brake HP	Date of Manufacture	Model Year	Displacement liters/cylinder (l/c)	Engine Manufacturer	Model No.
Non-Emergency Fire Pump	277	1987	1987	3.1	Cummins	NT855-F3

*{Permitting Notes: These compression ignition reciprocating internal combustion engines (CI RICE) are regulated under 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) adopted in Rule 62.204.800(11)(b), F.A.C. This permit section addresses "existing" non-emergency stationary CI RICE fire pump engines greater than **100 HP and less than 3**00 HP with a displacement of less than 10 liters per cylinder that are located at a major source of HAPs, that commenced construction before 6/12/2006; and, that have not been modified or reconstructed after this date.*

Link to 40 CFR 63, Subpart ZZZZ

Pursuant to Subpart IIII, NSPS for Stationary Compression Ignition RICE, these are "existing" emergency engines that commenced construction (ordered) before 7/11/2005 and that have not been modified or reconstructed after 7/11/2005. Therefore, they are not subject to Subpart IIII. The stack parameters for these engines are: stack height = 20 feet; exit diameter = 0.5 feet; exit temperature = 890°F; actual volumetric flow rate = 1,682 acfm. The source classification code for the firing of diesel fuel in these engines is 20100102.}

Essential Potential to Emit (PTE) Parameters

E.1. Methods of Operation - Fuel. These engines are allowed to burn diesel fuel. [Rule 62-213.410, F.A.C.]

E.2. Hours of Operation. The hours of operation for these engines are not restricted. [Rule 62-210.200(PTE), F.A.C., and, Application No. 0950137-054-AV]

Compliance

E.3. Continuous Compliance. Each unit shall be in compliance with the emission limitations and operating standards in this section at all times. [40 CFR 63.6605(a) & 63.6640(a)]

E.4. Operation and Maintenance of Equipment. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the compliance authority which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Condition **E.5.** is based on the specified averaging time of the applicable test method.

E.5. Carbon Monoxide. The emissions of carbon monoxide (CO) from each engine shall not exceed 230 ppmvd at 15% O_2. [40 CFR 63.6602 and Table 2c.3.]

{Permitting Note: These emissions units are also subject to the General Visible Emissions Standard in Facility-Wide Condition No. FW4.}

Excess Emissions

E.6. Engine Startup. During periods of startup the owner or operator must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63.6625(h)]

Test Methods and Procedures

{Permitting Note: Unless otherwise specified, averaging time(s) are based on the specified averaging time of the applicable test method.}

E.7. Test Methods. When required, tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
2-4	Velocity and Flow Rate, Gas Analysis, and Moisture Content
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [40 CFR 63, Subpart ZZZZ]

E.8. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

E.9. Compliance Tests Prior To Renewal. Each engine shall be tested to demonstrate compliance with the carbon monoxide limit shown in Specific Condition **E.5.** prior to obtaining a renewed operation permit. [Rules 62-210.300(2)(a) & 62-297.310(8)(b), F.A.C.]

E.10. Testing Requirements. Performance tests must be conducted according to the following requirements:

a. You do not need to start up the engines solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.
b. You must conduct three separate test runs for each performance test required in this section, as specified in 40 CFR 63.7(e)(3) (Link to 40 CFR 63.7). Each test run must last at least 1 hour, unless otherwise specified in this subpart and shall be conducted at normal representative operating conditions. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.
c. Test samples for CO, O_2, and moisture (if required) shall be collected from a single point located at the duct centroid.
d. Determine the O_2 concentration of the exhaust at the sampling port location using Method 3 or 3A or 3B of 40 CFR 60, Appendix A, or ASTM Method D6522-00 (Reapproved 2005). Measurements to determine O_2 concentration must be made at the same time and location as the measurements for CO concentration.

e. Measure moisture content of the exhaust at the sampling port location using Method 4 of 40 CFR 60, Appendix A, or Test Method 320 of 40 CFR 63, Appendix A, or ASTM D6348-03. Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.

f. Measure CO at the exhaust of the stationary RICE using Method 10 of 40 CFR 60, Appendix A, ASTM Method D6522-00 (2005), Method 320 of 40 CFR 63, Appendix A, or ASTM D6348-03. CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

g. You must normalize the CO concentrations to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(1) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_O = \frac{0.209\ F_d}{F_C} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(2) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 —15 percent O_2 , the defined O_2 correction value, percent.

(3) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d\ \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO adjusted to 15 percent O_2.

C_d = Measured concentration of CO, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

h. The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[40 CFR 63.7(e), 63.6620(a), (b), (d), (e)(2), (i), and Table 4.3.]

{Permitting Note: If the CO concentration required in paragraph f. is collected using a method that directly measures CO on a dry basis, then the moisture measurement in paragraph e. is not required.}

Recordkeeping and Reporting Requirements

E.11. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Conditions
Non-Compliance Reports	Semi-annually	**E.13.**
Semi-Annual Monitoring Reports	Semi-annually	**E.14.**

[Rule 62-213.440(1)(b), F.A.C.]

E.12. Notifications. The owner or operator must submit the following notifications:

a. *Notification of Performance Test.* You must notify the Compliance Authority in writing of your intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin in accordance with the requirements of 40 CFR 63.7(b)(1). Link to 40 CFR 63.7

b. *Notification of Compliance Status*. You must submit a notification of compliance status according to 40 CFR 63.9(h)(2)(ii). Link to 40 CFR 63.9

c. See also Specific Condition **E.17.**

[40 CFR 63.6645(a)(1), (g) & (h)]

E.13. Non-compliance Reports. You must report each instance in which you did not meet emissions limitation in Specific Condition **E.5.** You must also report each instance in which you did not meet the requirements in Specific Condition **E.17.** These instances are deviations from the emission and operating limitations in this permit. These deviations must be reported according to the requirements in Specific Condition **E.14.** [40 CFR 63.6640(b), 63.6640(e), 63.6650(a), and Table 7.1.a.]

E.14. Semi-Annual Monitoring Reports. You must report all deviations as defined in this section of the permit in the semiannual monitoring report required by Condition RR4. of Appendix RR, Facility-wide Reporting Requirements. These reports must contain the following information:

a. Company name and address.

b. Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

c. Date of report and beginning and ending dates of the reporting period.

d. If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

e. If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

f. The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

g. Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

[40 CFR 63.6650(c), (d) & (f)]

E.15. Notification, Performance and Compliance Records. The owner or operator must keep:

a. A copy of each notification and report that the owner or operator submitted to comply with this section, including all documentation supporting any Initial Notification or Notification of Compliance Status that the owner or operator submitted.

b. Records of the occurrence and duration of each malfunction of operation.
c. Records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii). [Link to 40 CFR 63.10]
d. Records of actions taken during periods of malfunction to minimize emissions in accordance with Specific Condition **E.4.**, including corrective actions to restore malfunctioning process and monitoring equipment to its normal or usual manner of operation.
[40 CFR 63.6655(a)]

E.16. Record Retention.
a. The owner or operator must keep records in a suitable and readily available form for expeditious reviews.
b. The owner or operator must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.
[40 CFR 63.6660 & 40 CFR 63.10(b)(1)]

General Provisions

E.17. 40 CFR 63 Subpart A - General Provisions. The owner or operator shall comply with the following applicable requirements of 40 CFR 63 Subpart A - General Provisions, which have been adopted by reference in Rule 62-204.800(11)(d)1., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 63.5(e), 40 CFR 63.5(f), 40 CFR 63.6(g), 40 CFR 63.6(h)(9), 40 CFR 63.6(j), 40 CFR 63.13, and 40 CFR 63.14. [Link to 40 CFR 63, Subpart A - General Provisions]

General Provisions Citation	Subject of Citation
§63.1	General applicability of the General Provisions
§63.2	Definitions (Additional terms defined in §63.6675)
§63.3	Units and abbreviations
§63.4	Prohibited activities and circumvention
§63.5	Construction and reconstruction
§63.6(a)	Applicability
§ 63.6(b)(5)	Notification
§ 63.6(c)(1)-(2)	Compliance dates for existing sources
§ 63.6(f)(2)	Methods for determining compliance
§ 63.6(f)(3)	Finding of compliance
§ 63.7(a)(3)	CAA section 114 authority
§ 63.7(b)(1)	Notification of performance test, except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling, except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan, except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities
§ 63.7(e)(2)	Conduct of performance tests and reduction of data
§ 63.7(e)(3)	Test run duration
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA
§ 63.7(f)	Alternative test method provisions
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting
§ 63.7(h)	Waiver of tests
§ 63.8(a)(2)	Performance specifications
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan

General Provisions Citation	Subject of Citation
§ 63.8(g)	Data reduction, except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements
§63.9(b)(1)–(5)	Initial notifications (Except that §63.9(b)(3) is reserved)
§ 63.9(e)	Notification of performance test, except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(g)(1)	Notification of performance evaluation, except that § 63.9(g) only applies as specified in § 63.6645
§ 63.9(h)(1)-(6)	Notification of compliance status
§63.9(i)	Adjustment of submittal deadlines
§63.9(j)	Change in previous information
§63.10(a)	Administrative provisions for recordkeeping/reporting
§63.10(b)(1)	Record retention
§63.10(b)(2)(vi)–(xi)	Records
§63.10(b)(2)(xii)	Record when under waiver
§63.10(b)(2)(xiv)	Records of supporting documentation
§63.10(b)(3)	Records of applicability determination
§63.10(d)(1)	General reporting requirements
§ 63.10(e)(3)	Excess emission and parameter exceedances reports, except that § 63.10(e)(3)(i) (C) is reserved.
§63.10(f)	Waiver for recordkeeping/reporting
§63.12	State authority and delegations
§63.13	Addresses
§63.14	Incorporation by reference
§63.15	Availability of information

[40 CFR 63.6665 & Table 8 to Subpart ZZZZ of Part 63]

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Subsection F. Surface Coating and Solvent Cleaning

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
021	Surface Coating and Solvent Cleaning

RACT Requirements

F.1. Cold Cleaning Control Technology. The permittee shall comply with each of the following requirements:

a. Equip the cleaner with a cover. The cover shall be so designed that it can be easily operated with one hand if:
   (1) The solvent volatility is greater than 0.3 pounds per square inch (15 millimeters of mercury or 2 kilopascals) measured at 100 degrees Fahrenheit (38 degrees Celsius);
   (2) The solvent is agitated;
   (3) The solvent is heated.

b. Equip the cleaner with a facility for draining cleaned parts. The drainage facility shall be constructed internally so that parts are enclosed under the cover while draining if the solvent volatility is greater than 0.6 pounds per square inch (31 millimeters of mercury or 4.1 kilopascals) measured at 100 degrees Fahrenheit (38 degrees Celsius), except that the drainage facility may be external for the applications where an internal type cannot fit into the cleaning system.

c. Install one of the following control devices if the solvent volatility is greater than 0.6 pounds per square inch (31 millimeters of mercury or 4.1 kilopascals) measured at 100 degrees Fahrenheit (38 degrees Celsius), or if the solvent is heated above 120 degrees Fahrenheit (50 degrees Celsius):
   (1) Freeboard that gives a freeboard ratio greater than or equal to 0.7; or,
   (2) Water cover (solvent must be insoluble in and heavier than water); or,
   (3) Other systems of equivalent control such as refrigerated chiller or carbon absorption.

d. Provided a permanent, conspicuous label summarizing the operating requirements.

e. Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, such that greater than 20 percent of the waste solvent (by weight) can evaporate into the atmosphere.

f. Close the cover whenever parts are not being handled in the cleaner.

g. Drain the cleaned parts for at least 15 seconds or until dripping ceases.

h. If used, supply a solvent spray that is a solid fluid stream (not a fine, atomized, or shower-type spray) at a pressure which does not cause excessive splashing.

[Rule 62-296.511, F.A.C.]

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Federal Acid Rain Program Provisions

Operated by: Orlando Utilities Commission
Plant: Stanton Energy Center
ORIS Code: 0564

The emissions units listed below are regulated under Acid Rain, Phase II.

EU No.	EPA ID	Brief Description
001	1	Fossil Fuel Fired Steam Generator # 1
002	2	Fossil Fuel Fired Steam Generator # 2
037	B	300 megawatt (MW) Combined Cycle Combustion Turbine – Stanton Unit B

A.1. The Phase II Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the applications listed below:

a. DEP Form No. 62-210.900(1)(a)3, dated 09/27/17, received 10/02/17.
b. DEP Form No. 62-210.900(1)(a), dated 09/27/17, received 10/02/17.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Nitrogen oxide (NO_X) requirements for each Acid Rain Phase II unit are as follows:

EU No.	EPA ID	NO_X Limit
001	**1**	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2018 through calendar year 2022. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.
002	**2**	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2018 through calendar year 2022. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

A.3. Sulfur Dioxide (SO_2) Emission Allowances. SO_2 emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

A.4. Comments, Notes, and Justifications: None.

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Florida Department of Environmental Protection

Phase II NOx Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: New ☐ Revised ☐ Renewal ☒ Page 1 of 3

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Plant Name Stanton Energy Center	State FL	ORIS Code 564
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# 1 Type DWB	ID# 2 Type DWB	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☒	☒	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☐	☐	☐	☐	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

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Plant Name (from Step 1) Stanton Energy Center

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STEP 2, cont'd.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type DWB	Type DWB	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☐	☐	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its

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attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Chip Merriam, VP, Legislative and Regulatory Affairs	
Signature	Date 9-27-17

Contact Information

Email Address: cmerriam@ouc.com
Phone: (407) 434 - 2201

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Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☐ New ☐ Revised ☒ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name	State	ORIS/Plant Code
Stanton Energy Center	**FL**	**564**

STEP 2
Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO_2 Opt-in unit, enter "yes" in column "b".

For new units or SO_2 Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
B	**NO**	Yes	3-1-2010	6-1-2010
1	**NO**	Yes		
2	**NO**	Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

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Plant Name (from STEP 1) Stanton Energy Center

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from STEP 1) Stanton Energy Center

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4
For SO_2 Opt-in units only.

In column "f" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

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Plant Name (from STEP 1) Stanton Energy Center

STEP 5

For SO_2 Opt-in units only.
(Not required for SO_2 Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO_2 Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO_2 Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO_2 Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO_2 Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

A. If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
B. A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
C. A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
D. Attach a complete compliance plan for SO_2 under 40 CFR 72.40.
E. The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
F. The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature [signature] Date Sept 27, 2017

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **Chip Merriam** | Title **V.P. Legislative and Regulatory Affairs**

Owner Company Name **Orlando Utilities Commission**

Phone **(407) 434-2204** | E-mail address cmerriam@ouc.com

Signature [signature] Date Sept 27, 2017

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