Orlando Utilities Commission, Stanton Energy Center
Title V Air Operation Permit Renewal
Permit No. 0950137-044-AV

APPLICANT

The applicant for this project is Orlando Utilities Commission. The applicant's responsible official and mailing address are: Mr. Chip Merriam, Vice President, Orlando Utilities Commission, Stanton Energy Center, P.O. Box 3193, Orlando, Florida 32802.

PROJECT DESCRIPTION

The purpose of this permitting action is to renew the Title V air operation permit for the facility.

FACILITY DESCRIPTION

The applicant operates the existing Stanton Energy Center, which is located in Orange County at 5100 South Alafaya Trail, Orlando, Florida.

The existing Curtis H. Stanton Energy Center consists of the following units:

- Fossil fuel fired steam generator (FFSG) No. 1 (Emission Unit 001) consists of a Babcock and Wilcox wall fired dry bottom boiler (Model RB 611) and steam turbine which drives a generator with a nameplate rating of 468 megawatts. FFSG No.1 began commercial operation on May 12, 1987.
- FFSG No. 2 (Emission Unit 002) 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 megawatts. FFSG No. 2 began commercial operation on March 29, 1996.

  Each unit has its own 550 foot exhaust stack and is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization. The maximum heat input for each unit is 4,800 MMBtu per hour. Pipeline quality natural gas, as well as landfill gas, is also approved for combustion, although petroleum coke is not approved. 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 flue gas desulfurization equipment manufactured by Combustion Engineering. These units are certified under the Florida Power Plant Siting Act.

  Generally speaking, the emission limits for FFSG No. 2 are more stringent than those for FFSG No. 1, as can be seen from the permitted SO_2 and NO_X emission rates stated in the permit. Due to nearly 9 years of time (1987-1996) which elapsed between the startup of these units, the PSD requirements for each unit were different, reflecting improvements in available control technology in later years.
- Coal processing and conveying equipment including breakers and crushers; limestone and pebble lime handling equipment (Emission Units 004 - 010). Particulate matter emissions generated are controlled by baghouses in addition to reasonable precautions.
- Fly Ash Silos No. 1 and No. 2 (Emissions Units 011 - 016 and 029) handle fly ash from FFSG Units No. 1 and No. 2 respectively. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silos No. 1 and No. 2 and then is gravity fed by tubing into totally enclosed tanker trucks. Particulate matter emissions generated by silo loading and unloading to a tanker truck is controlled by baghouses in addition to reasonable precautions.
- Two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators designated as Unit A (Emission Units 025 and 026) equipped with evaporative coolers on the inlet air system; two supplementary fired heat recovery steam generators (HRSG); and one steam turbine-electrical generator rated at approximately 300 MW. These units began commercial operation on April 28, 2003.

These combustion turbine generators ("2-on-1") have a total nominal capacity of 640 MW and achieve approximately 700 megawatts during extreme winter peaking conditions. These emission units are equipped with Dry Low NO_X (DLN) combustors as well as a selective catalytic reduction (SCR) system in order to control NO_X emissions to 3.5 parts per million by volume, dry basis (ppmvd) at 15% O_2 while firing natural gas. During fuel oil firing, emissions shall be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Stack parameters are the same for both units. Pipeline quality natural gas, 0.05% sulfur oil, and good combustion practices shall be employed to control all pollutants.

- Unit B (Emission Unit 037) is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA combustion turbine generator (CTG) equipped with evaporative inlet air cooling and power (steam) augmentation equipment; a supplementary-fired heat recovery steam generator (HRSG) with a nominal 531 MMBtu/hr duct burner (DB); a HRSG stack; and a nominal 150 MW steam electric generator (STG). This unit began commercial operation on October 27, 2009.

  Unit B is equipped with Dry Low nitrogen oxide (NO_X) combustors as well as a selective catalytic reduction (SCR) system in order to control NO_X emissions to 2 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% ultra-low fuel sulfur oil, and good combustion practices shall be employed to control all pollutants.
- Unit B six-cell mechanical cooling tower (Emission Unit 038) with individual exhaust fans and drift eliminators, and;
- Unit B Nominal 1,000,000 gallons ultra-low sulfur diesel (ULSD) fuel oil storage tank (Emission Unit 039).

A summary of the regulated emission units (EU) at the facility is given below:

EU No.	Brief Description
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
010	Coal Reclaim Hopper Baghouse
011	Flyash Exhauster Filter #1 Baghouse
012	Flyash Exhauster Filter #2 Baghouse
013	Flyash Exhauster Filter #3 Baghouse
014	Flyash Exhauster Filter #4 Baghouse
015	Flyash Silo Bin Vent Filter Baghouse
016	Adipic Acid Storage Baghouse
021	Surface Coating and Solvent Cleaning
024	3,740 BHP Emergency Generator
025	Stanton Unit A- Combined-Cycle Combustion Turbine
026	Stanton Unit A- Combined-Cycle Combustion Turbine
029	Flyash Silo Bin Vent Filter Baghouse

EU No.	Brief Description
037	Stanton Unit B - 300 MW Combined Cycle Combustion Turbine
038	Stanton Unit B - Cooling Tower
041	563 kW Emergency Generator at the Stanton A Plant Site
044	Emergency Fire Pump Engines

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

PRIMARY REGULATORY REQUIREMENTS

Title III: The facility is identified as a major source of hazardous air pollutants (HAP).

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

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 62-213, Florida Administrative Code (F.A.C.).

PSD: The facility is a Prevention of Significant Deterioration (PSD)-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility operates units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60. The emission units subject to NSPS requirements are summarized below.

Regulation	EU No(s).
40 CFR 60, Subpart A, NSPS General Provisions	001, 002, 025, 026
40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators	001, 002
NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800	025, 026
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
NSPS- 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels	028
NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants	004 through 016 and 029
NSPS - 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	041

NESHAP: The facility operates units subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63. The emission units subject to NESHAP requirements are summarized below.

Regulation	EU No(s).
NESHAP - 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)	024, 041, 044
NESHAP - 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units	001, 002

CAIR: The facility operates units subject to the Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.

Siting: The facility operates units that were certified under the Florida Power Plant Siting Act, 403.501-518, F.S., and Chapter 62-17, F.A.C.

CAM: Compliance Assurance Monitoring (CAM) does apply to certain units at the facility.

The FFSG No. 1 and No. 2 are subject to 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. FFSG No.1 and No. 2 are not subject to CAM for the controlled emissions of sulfur dioxide because the SO_2 CEMS are used as a continuous compliance determination method.

The combined cycle combustion turbines (Emissions Units 025 and 026) and the combined cycle Unit B (Emission Unit 037) are not subject to CAM because the NO_X CEMS is used for continuous compliance determination. Thus no CAM plan is included for these units in this permit.

PROJECT REVIEW

The processing of an air construction revision is concurrent with the processing of the Title V air operation permit renewal for the facility. The requested revisions are to reflect site conditions, including:

- The removal of the auxiliary boiler and oil-firing capability in Units 1 and 2 (as well as associated No. 6 oil storage tanks) which now represent obsolete conditions. Consequently, all references to fuel oils firing, and associated emission limits, test methods, reporting requirements, etc. were removed from Subsection III-A (Coal Fired Steam Generators, EU 001 and 002) of the renewed Title V permit. In addition, Subsections III-B (Auxiliary Boiler, EU 003), Subsection III-E (Distillate Fuel Oil Storage Tank, EU 028) and Subsection III-H (Stanton Unit B - Distillate Fuel Oil (0.0015% S) Storage Tank, EU 039) were removed from the permit.
- The permit has been changed to reflect certain newly effective federal ("MACT") regulations. Specifically, Emissions Units 001 and 002 (the Fossil Fuel Fired Steam Electric Generators) are subject to 40 CFR 63, Subpart UUUUU- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units since Fossil Fuel Fired Steam Electric Generators are fossil fuel-fired combustion units of more than 25 megawatts. The Fossil Fuel Fired Steam Electric Generators are classified as "existing" units since they were constructed prior to May 3, 2011 and have not been reconstructed. In addition, the Fossil Fuel Fired Steam Electric Generators are considered coal-fired units not using low rank virgin coal. The Fossil Fuel Fired Steam Electric Generators must come into compliance with the requirements of Subpart UUUUU no later than April 16, 2015. Subpart UUUUU applies the following emission limits to the Fossil Fuel Fired Steam Electric Generators (EU 001 and 002):

  1. *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 5.0×10^{-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:
     a. Antimony (Sb) – 0.80 pounds per terra Btu (lb/TBtu) or 8.0×10^{-3} lb/GWh.
     b. Arsenic (As) – 1.1 lb/TBtu or 0.020 lb/GWh.
     c. Beryllium (Be) – 0.20 lb/TBtu or 2.0×10^{-3} lb/GWh.
     d. Cadmium (Cd) – 0.30 lb/TBtu or 3.0×10^{-3} lb/GWh.
     e. Chromium (Cr) – 2.8 lb/TBtu or 0.030 lb/GWh.
     f. Cobalt (Co) – 0.80 lb/TBtu or 8.0×10^{-3} lb/GWh.
     g. Lead (Pb) – 1.2 lb/TBtu or 0.020 lb/GWh.
     h. Manganese (Mn) – 4.0 lb/TBtu or 0.050 lb/GWh.

i. Nickel (Ni) – 3.5 lb/TBtu or 0.040 lb/GWh.

j. Selenium (Se) – 5.0 lb/TBtu or 0.060 lb/GWh.

2. *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.

3. *Mercury (Hg)*. Emissions of Hg shall not exceed either 1.2 lb/TBtu or 0.013 lb/GWh.

   Compliance with the above emissions limits shall be demonstrated pursuant to one of the available options specified in 40 CFR 63, Subpart UUUUU which is included as an appendix in the renewed Title V permit. The permittee shall also comply with the recordkeeping and reporting requirements specified in the appendix.

- Incorporate the conditions from several air construction permits. The activities authorized under the air construction permits have been completed, and OUC requested that the applicable requirements be incorporated into the renewed TV permit. The applicable air construction permits include:
  - Permit No. 0950137-014-AC. Addition of forced oxidation to Units 1 and 2 FGD systems
  - Permit No. 0950137-034-AC. Unit 1 FGD system upgrade
  - Permit No. 0950137-039-AC. Replacement of the fuel oil igniters with natural gas igniters
  - Permit No. 0950137-040-AC. Add DSI to Units 1 and 2, Unit 1 FGD upgrades
  - Permit No. 0950137-041-AC. Unit 2 steam turbine upgrade

- Changes are being made to the facility's current Title V permit as part of this renewal project to incorporate the revisions authorized by permit No. 0950137-043-AC, which is being processed concurrently. These requests were proposed by OUC in the application received May 20, 2014.

- Changes in the descriptions of the emissions unit sections were made in the renewed Title V permit to reflect the changes described above.

The Department reviewed all these requests and approves the revised language as indicated below. The revised language is highlighted in yellow with ~~Strikethrough~~ indicating deletions and double underline indicating new language.

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 Nos.	MMBtu/hr Heat Input	Fuel Type
001	4,800	Coal, ~~No. 6 fuel oil, on-site generated lubricating oil and used fuel oil which meets the requirements of 40 CFR 266.40,~~ 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.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,
   ~~(3) New No. 6 fuel oil,~~
   ~~(4) On-site generated lubricating oil,~~
   ~~(5) On-specification used oil (see Specific Condition **A.34.**),~~ and
   (~~6~~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 scrubber shall be put into service during normal operational startup, and shutdown, when No. 6 fuel oil is being burned.~~ 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) and 62-213.410, F.A.C.; 40 CFR 60.40Da, and PSD-FL-084;]

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;
   ~~(2) 0.03 lb/million Btu and 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel (No. 6 fuel oil);~~ or,

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) 0.03 lb/million Btu and 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel (No. 6 fuel oil); or,~~
   (~~3~~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 PSD-FL-084/PA 81-14/SA1;]

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.
      (c) 1.2 lb/MMBtu heat input, maximum two hour average, and 1.14 lb/MMBtu, heat input maximum three hour average.

   ~~(2) When combusting liquid fuel (No. 6 fuel oil):~~
   ~~(a) 0.80 lb/million Btu heat input, and 10 percent of the potential combustion concentration (90 percent reduction); or,~~
   ~~(b) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.20 lb/MMBtu heat input.~~

   (~~3~~2) ~~When different fuels are combusted simultaneously in Unit No. 1, the applicable standard for sulfur dioxide is determined by proration using the following formulas:~~
   ~~(a) If emissions of sulfur dioxide to the atmosphere are greater than 0.60 lb/million Btu heat input:~~
   ~~Es = the lesser of (0.80x + 1.20y)/100 or 1.14 and %Ps = 10~~
   ~~(b) If emissions of sulfur dioxide to the atmosphere are equal to or less than 0.60 lb/million Btu heat input:~~
   ~~Es = the lesser of (0.80x + 1.20y)/100 or 1.14 and %Ps = (10x + 30y)/100~~
   ~~where:~~
   ~~Es = the sulfur dioxide emission limit (lb/million Btu heat input).~~
   ~~%Ps = the percentage of potential sulfur dioxide emission allowed.~~
   ~~x = the percentage of total heat input derived from the combustion of liquid fuel.~~
   ~~y = the percentage of total heat input derived from the combustion of solid fuel.~~

b. *Unit No. 2*.

(1) When Combusting solid fuel.

(a) 0.25 lb/million Btu (30-day rolling average) heat input;

(b) 0.67 lb/million Btu (24-hour emission rate) heat input; or

(c) 0.85 lb/million Btu (3-hour emission rate) heat input.

~~(2) When combusting liquid fuel (No. 6 fuel oil):~~

~~(a) 0.80 lb/million Btu heat input, and 10 percent of the potential combustion concentration (90 percent reduction); or,~~

~~(b) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.20 lb/MMBtu heat input.~~

~~(3~~2) ~~When different fuels are combusted simultaneously in Unit No. 2, the applicable standard of sulfur dioxide is determined by proration using the following formulas:~~

~~(a) If emissions of sulfur dioxide to the atmosphere are greater than 0.60 lb/million Btu heat input:~~

~~Es = the lesser of (0.80x + 1.20y)/100 or 0.85 and %Ps = 10~~

~~(b) If emissions of sulfur dioxide to the atmosphere are equal to or less than 0.60 lb/million heat input:~~

~~Es = the lesser of (0.80x + 1.20y)/100 or 0.85 and %Ps = (10x + 30y)/100~~

~~where:~~

~~Es = the sulfur dioxide emission limit (lb/million Btu heat input).~~

~~%Ps = the percentage of potential sulfur dioxide emission allowed.~~

~~x = the percentage of total heat input derived from the combustion of liquid fuel.~~

~~y = the percentage of total heat input derived from the combustion of solid fuel.~~

c. *Unit 1 and 2 Averaging Time*. Except as specified in paragraphs a.(1)(c) and b.(1)(b) & (c), 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.

[Rule 62-204.800(8), F.A.C.; 40 CFR 60.43Da; PSD-FL-084/PPS PA 81-14/SA1; and, PA 81-14C & PA81-14SA issued 12/24/97]

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.

~~(2) When combusting liquid fuel, nitrogen oxide emissions shall not exceed shall not exceed 0.30 lb/million Btu heat input (30-day rolling average).~~

~~(3~~2) ~~When liquid and solid fuels are combusted simultaneously in Unit No. 1, the applicable standard for nitrogen oxides is determined by proration using the following formula:~~

~~En = [0.30 x + 0.60 y]/100~~

~~where:~~

~~En = the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (lb/million Btu heat input).~~

~~x = the percentage of total heat input derived from the combustion of liquid fuels.~~

~~y = the percentage of total heat input derived from the combustion of solid fuels.~~

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).

~~(2) When combusting liquid fuel, nitrogen oxide emissions shall not exceed shall not exceed 0.30 lb/million Btu heat input (30-day rolling average).~~

~~(3~~2)~~When liquid and solid fuels are combusted simultaneously in Unit No. 2, the applicable standard for nitrogen o~~

~~En = [0.30 x + 0.17 y]/100~~

~~where:~~

~~En = the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (lb/million Btu heat input).~~
~~X = the percentage of total heat input derived from the combustion of liquid fuels.~~
~~Y = the percentage of total heat input derived from the combustion of solid fuels.~~

c. *Units 1 and 2*. The above standards apply at all times except during periods of startup, shutdown, or malfunction.
[Rule 62-204.800(8) and 62-214, F.A.C.; and 40 CFR 60.44Da]

- Units 1 and 2 are now subject to 40 CFR 63, Subpart UUUUU.

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
3~~B~~A	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
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. [62-297.401, F.A.C.; PPS PA 81-14/SA1; PSD-FL-084; and 40 CFR 60.49Da]

A.33. Fuel Sampling Record. Samples of all ~~fuel oil and~~ coal fired in the boilers shall be taken and analyzed for sulfur content, ash content, and heating value. ~~Accordingly, samples shall be taken of each fuel oil shipment received.~~ 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]

~~**A.34.** Used Oil. Burning of on-specification used oil is allowed at this facility in accordance with all other conditions of this permit and the following conditions:~~

~~a. *On-specification Used Oil Allowed as Fuel*. This permit allows the burning of used fuel oil meeting EPA "on-specification" used oil specifications,with a maximum sulfur content of 1.5 percent by weight for Units 1 and 2 and 0.5 percent by weight for the auxiliary boiler. The PCB concentration of used oil shall be less than 50 ppm. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility. On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]~~

~~Arsenic shall not exceed 5.0 ppm;~~
~~Cadmium shall not exceed 2.0 ppm;~~
~~Chromium shall not exceed 10.0 ppm;~~
~~Lead shall not exceed 100.0 ppm;~~
~~Total halogens shall not exceed 1000 ppm;~~
~~Flash point shall not be less than 100 degrees F.~~

~~b. *Quantity Limited*. The maximum amount of on-specification used oil that can be burned at this facility shall be limited to 1.5 million gallons during each calendar year.~~

~~c. *Used Oil Containing PCBs Not Allowed*. Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.~~

~~d. *PCB Concentration of 2 to less than 50 ppm*. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.~~

~~e. *Testing Required*. The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters: Arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition. If the analytical results show that the used oil does not meet the specification for on-specification used oil, or that it contains a PCB concentration of 50 ppm or greater, the owner or operator shall:~~

~~(1) immediately notify the Central District Office in Orlando;~~
~~(2) provide the analytical results for the above parameters; and~~
~~(3) indicate the proposed means of disposal of the used oil.~~

~~f. *Record Keeping Required*. The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)]~~

~~(1) The gallons of on-specification used oil generated and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)~~
~~(2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)~~
~~(3) Results of the analyses required above.~~
~~(4) The total amount of lead emitted from burning used oil each month (calculated from the amount burned, the specific gravity of the used oil and the concentration of lead in the~~

~~used oil), and the total amount of lead emitted in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)~~

~~g. *Reporting Required*. The owner or operator shall submit to Central District Office in Orlando, within thirty days of the end of each calendar quarter, the analytical results and the total amount of on-specification used oil generated and burned during the quarter. Also, the owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year. [Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761]~~

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

A.37. 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.}

D.9. Permitted Capacity.

a. *Combustion Turbine*. The maximum heat input rates to each CT/HRSG shall not exceed 2,402 million Btu (HHV) per hour (MMBtu/hr) when firing natural gas with duct burner firing and power augmentation. The maximum heat input rates to each CT/HRSG shall not exceed 2,068 MMBtu/hr

(HHV) when firing fuel oil. Manufacturer's curves corrected for ISO conditions were provided to the Department of Environmental Protection (DEP) within 45 days prior to the completion of the initial compliance testing.

b. *Heat Recovery Steam Generator equipped with Duct Burner*. The maximum heat input rate of the natural gas fired duct burner shall not exceed 533 MMBtu/hour (LHV) (590 MMBtu/hour (HHV)) at any temperature or under any scenario.

[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and 0950137-002-AC, Specific Conditions 10 and 11.]

D.14. Carbon Monoxide (CO) Emissions. Emissions of CO in the stack exhaust gas ~~(at ISO conditions)~~ with the combustion turbine operating on natural gas shall not exceed 17 ppmvd @15% O_2 on a 24-hour block average to be demonstrated by CEMS; or 14 ppmvd @15% O_2 with the CT operating on fuel oil on a 24-hr block average to be demonstrated by CEMS. These limits shall also be demonstrated by annual stack test using EPA Method 10 or through annual relative accuracy test audit (RATA) testing. [BACT Determination; Rule 62-212.400, F.A.C.; and 0950137-002-AC, Specific Condition 22.]

D.21. Selective Catalytic Reduction System (SCR) Compliance Procedures.

a. At permit renewal an ~~An annual~~ a test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner and operating on the primary fuel. The RATA for NO_X may be used in lieu of stack testing. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.

D.26. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), each EU shall be tested to demonstrate compliance with the emissions standards for visible emissions, carbon monoxide, and nitrogen oxides ~~and ammonia slip~~. The Relative Accuracy Test Audits (RATA) for NO_X and CO CEMS may be used in lieu of annual stack testing for these pollutants. A VE tests is not required when firing fuel oil so long as total fuel oil firing during the fiscal year is less than 400 hours. An annual VE test is required when firing the primary fuel. Ammonia Slip testing while firing the primary fuel is required prior to the renewal of each operation permit. [Rule 62-297.310(7), F.A.C.; and Permit No. 0950137-002-AC; 0950137-043-AC, Specific Condition 2.]

F.23. Annual Compliance Tests. During each federal fiscal year (October 1st, to September 30th) 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. ~~Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel.~~ NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. 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) and 62-297.310(7)(a)(4) & (8), F.A.C.; and, Permit Nos. 0950137-020-AC/PSD-FL-373A, Specific Condition A.23. and 0950137-036-AC (PSD-FL-395A, PSD-FL-373B), Specific Condition B.6.; 0950137-043-AC, Specific Condition 3.]

F.23.a. Compliance Tests Prior to Renewal. At permit renewal a stack emission test for nitrogen oxides and ammonia slip from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner and operating on the primary fuel. The RATA for NO_X may be used in lieu of stack testing. 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 F.13. [0950137-043-AC, Specific Condition 3.]

- In addition to the changes authorized by the concurrent air construction permit, changes were made to the Title V permit deemed appropriate under Title V revision guidelines. The addition of alternate test methods was requested by the applicant. The units affected no longer utilize used oil. The higher heating

value of the maximum heat input rate of the duct burner was added as requested by the applicant. These follow below:

The application also requested revisions to the designations (i.e., regulated, unregulated and insignificant) of several emission units, including EU ID Nos. 018, 021, 024, 028, 039, and proposed 044. The requested revision of EU 018, EU 028, and EU 039 into a new "insignificant" emission unit category referred to as "miscellaneous tanks" is due to the removal of the No. 6 oil storage tank from EU 018 (EU 018 now only consists of a No. 2 oil storage tank), as well as the calculated emissions potential from these units. The calculations for EU 028 were run on the TANKS program and were attached to the application. They indicate that potential emissions are well below the 5 TPY threshold that would qualify them as insignificant. Potential emissions for EU 018 and EU 039 were assumed to be similar to EU 028 based on tank size and material stored. EU 021, surface coating and solvent cleaning, is regulated and now has its own section in the permit. These changes were approved by the Department and are reflected in the renewed Title V permit.

Finally, emergency generators regulated under the reciprocating internal combustion engines (RICE) rules were added to the permit as new separate sections.

Fuel Oil Use - Stanton Unit A consists of two nominal 170 MW General Electric "F" Class combustion turbines (EU Nos. 025 and 026) fired primarily with natural gas, but with fuel oil as a secondary, back-up fuel. While fuel oil is available as a secondary fuel, Stanton Unit A has not fired on oil for more than two years. No permit renewal tests for operation on fuel oil have been conducted because Stanton Unit A has been out of operation as an oil-fired unit. Given their limited oil-fired operation, there is no valid reason to require these units to test on fuel oil prior to permit renewal. Requiring such testing would mean combusting fuel oil purely for that purpose, resulting in unnecessary costs and unnecessary emissions for those hours of operation.

To address this issue, a compliance plan has been included in the Appendix to the Title V air operation permit. Pending Departmental rule changes may eliminate stack testing for a fuel type not currently being utilized by an emissions unit. If such rule changes are not made, or in the event Stanton Unit A fires oil in the future, the required oil-fired compliance tests shall be conducted by the permittee as soon as practicable upon next firing fuel oil, but no later than 60 days thereafter.

PROCESSING SCHEDULE AND RELATED DOCUMENTS

- Application for a Title V Air Operation Permit Revision received May 20, 2014. The application was deemed complete.
- Issuance of the draft/proposed Title V air operation permit package on August 8, 2014.
- Publication of the Public Notice on August 30, 2014.

CONCLUSION

This Title V air operation permit renewal is issued under the provisions of Chapter 403, Florida Statues (F.S.), and Chapters 62-4, 62-210, 62-213 and 62-214, F.A.C.