Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

February 27, 2004

Mr. Ronald H. Walston
Alternative Responsible Official
Southern Company
P.O. Box 781295
Orlando, FL 32878

Re: PROPOSED Title V Air Operation Permit Revision
0950137-005-AV
Curtis H. Stanton Energy Center
Facility ID: **0950137**; ORIS Codes: **0564** and **55821**

Dear Mr. Walston:

One copy of the "PROPOSED PERMIT REVISION DETERMINATION" for the Curtis H. Stanton Energy Center, located at 5100 Alafaya Trail, Orlando, Orange County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

An electronic version of this determination has been posted on the Division of Air Resource Management's world wide web site for the United States Environmental Protection Agency (U.S. EPA) Region 4 office's review. The web site address is:

http://www.dep.state.fl.us/air/permitting/airpermits

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the USEPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn. If you have any questions, please contact Tom Cascio at 850/921-9526.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Copy furnished to:
Frederick F. Haddad, Primary Responsible Official, Orlando Utilities Commission
G. Dwain Waters, Gulf Power
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)
Len Kozlov, P.E., Central District Office
Thomas W. Davis, P.E., Environmental Consulting & Technology, Inc.

PROPOSED Permit Revision Determination
Curtis H. Stanton Energy Center
Permit No. **0950137-005-AV**

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" to the OUC/KUA/FMPA/Southern Company – Florida, LLC, for the Curtis H. Stanton Energy Center, located at 5100 Alafaya Trail, Orlando, Orange County, was clerked on January 8, 2004. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" was published in the Orlando Sentinel on January 15, 2004.

The DRAFT Title V Air Operation Permit was available for public inspection at the Department of Environmental Protection's Central District Office in Orlando and the permitting authority's office in Tallahassee. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" was received on January 22, 2004.

II. Public Comment(s).

Comments were received, but the DRAFT Title V Operation Permit was not reissued. The comments were not considered significant enough to reissue the DRAFT Title V Permit and require another Public Notice. The only comments received were from the Applicant in a letter received on February 12, 2004. Listed below are responses to the significant comments in the letter. The comments are not restated.

No.	Permit Specific Condition Reference	Department Response
1	Statement of Basis, Section I, Facility Description, and Section III, Subsection E. Description.	The recommended change to add the descriptive sentence "Units 25 and 26 have a total nominal capacity of 640 MW and will achieve approximately 700 megawatts during extreme winter peaking conditions" is acceptable, and has been made in the PROPOSED permit.
2	Specific Condition **E.14.**	The typographical correction (reference to Specific Condition **E.36.**) has been made in the PROPOSED permit.
3	Section III, Subsection F. Description.	The storage tank volume correction (1.86 million gallons) has been made in the PROPOSED permit.

III. Conclusion.

The permitting authority hereby issues PROPOSED Title V Permit No. 0950137-005-AV, with the changes noted above.

STATEMENT OF BASIS

Orlando Utilities Commission
and
OUC/KUA/FMPA/Southern Company – Florida, LLC

Curtis H. Stanton Energy Center

Facility ID No. **0950137**
Orange County

Title V Air Operation Permit Revision
Permit No. **0950137-005-AV**

This 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 perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

The purpose of this permit is to revise the facility's current Title V Air Operation Permit to include two additional dual fuel combined-cycle units, with heat recovery steam generators (emission units 025 and 026). Each new unit is a 170-megawatt General Electric combustion turbine-generator with a 160-foot stack. These emissions units are not subject to compliance assurance monitoring (CAM) because the NO_X CEMS is used for continuance compliance determination. Thus, no CAM plan is included in this permit.

This facility consists primarily of two fossil fuel fired steam electric generating stations, an auxiliary boiler, two combined-cycle combustion turbines, and solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities.

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. 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 Megawatts. Each boiler/steam generator is a wall fired dry bottom unit. Unit Nos. 1 and 2 are fired with coal, with No. 6 fuel oil used for startup and flame stabilization. Each unit has their individual stacks. An auxiliary boiler, which serves both boilers and has a maximum heat input of 83 MMBtu/hour, is located at the facility. The auxiliary boiler is fired with No. 2 distillate fuel oil.

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 and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour. Pipeline quality natural gas as well as landfill gas is also approved for combustion, although petroleum coke is not approved.

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 and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour. Pipeline quality natural gas as well as landfill gas is also approved for combustion, although petroleum coke is not approved. Each boiler/steam generator, units #1 and #2 drives a turbine generator and both units have an individual 550-foot exhaust stack. 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%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Combustion Engineering.

Both boiler/steam generators (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.; and 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), F.A.C.; 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). Fossil fuel fired steam generator # 1 began commercial operation on May 12, 1987; and, fossil fuel fired steam generator # 2 began commercial operation on March 29, 1996. Due to the many (nearly 9) years of time which elapsed between the startup of these units, the PSD requirements are different, reflecting improvements in available control technology. Generally speaking, the emission limits for unit #2 are more stringent than those for unit #1, as can be seen from the permitted SO_2 and NO_X emission rates.

The auxiliary boiler is designated as Unit No. 3. The unit is a Babcock & Wilcox Model No. FM-2919 boiler. It is fired primarily with "new oil", which means an oil which has been refined from crude oil and has not been used. Only No. 2 fuel oil can be burned in the auxiliary boiler. This auxiliary boiler serves both Unit No. 1 and 2 boiler/steam generators. The emission unit is regulated under Rule 62-210.300, F.A.C., Permits Required.

Fly Ash Silos No. 1 and No. 2 handle fly ash from Steam Generators 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. The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.

Emission units -025 and -026 are nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system, two supplementary fired heat recovery steam generators (HRSGs), each with a 160 ft. stack, and one steam turbine-electrical generator rated at approximately 300 MW. The combustion turbines are equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 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. Pipeline quality natural gas, 0.05% sulfur oil, and good combustion practices shall be employed to control all pollutants. Units 25 and 26 have a total nominal capacity of 640 MW and will achieve approximately 700 megawatts during extreme winter peaking conditions.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities. Based on the Title V permit revision application received on October 31, 2003, this facility is not a major source of hazardous air pollutants (HAPs).

Orlando Utilities Commission
and
OUC/KUA/FMPA/Southern Company – Florida, LLC

Curtis H. Stanton Energy Center

Facility ID No. **0950137**
Orange County

Title V Air Operation Permit Revision
PROPOSED Permit No. **0950137-005-AV**

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Permittee:
Orlando Utilities Commission and
OUC/KUA/FMPA/Southern Company
– Florida, LLC

PROPOSED Permit Revision No. **0950137-005-AV**
Facility ID No.: 0950137
SIC Nos.: 4911
Project: Title V Air Operation Permit Revision

This permit revision is for the operation of the Curtis H. Stanton Energy Center. This facility is located at 5100 Alafaya Trail, Orlando, Orange County; UTM Coordinates: Zone 17, 484.00 km East and 3150.50 km North; Latitude: 28° 28' 50" North and Longitude: 81° 09' 40" West.

This Title V air operation permit revision 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 perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit revision.

Referenced attachments made a part of this permit:
Phase II Acid Rain Part Application signed by the Designated Representative on 04/15/02
Phase II NO_x Acid Rain Part Application (Revised) received on August 17, 1999
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-4, TITLE V CONDITIONS (version dated 02/12/02)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE
SUMMARY REPORT- GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (40 CFR 60, July 1996)
Appendix GG, Standards of Performance for Stationary Gas Turbines

Effective Date: January 1, 2000
Revision Effective Date:
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

Michael G. Cooke, Director
Division of Air Resource Management

MGC/tbc

PROPOSED Permit Revision No. 0950137-005-AV

Table of Contents

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. 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. 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 Megawatts. Each boiler/steam generator is a wall fired dry bottom unit. Unit Nos. 1 and 2 are fired with coal, with No. 6 fuel oil used for startup and flame stabilization. Each unit has their individual stacks. An auxiliary boiler, which serves both boilers and with a maximum heat input of 83 MMBtu/hour, is located at the facility. The auxiliary boiler is fired with No. 2 distillate fuel oil.

Emission units -025 and -026 are nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system, two supplementary fired heat recovery steam generators (HRSGs), each with a 160 ft. stack, and one steam turbine-electrical generator rated at approximately 300 MW. Units 25 and 26 have a total nominal capacity of 640 MW and will achieve approximately 700 megawatts during extreme winter peaking conditions.

The combustion turbines are equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 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. Pipeline quality natural gas, 0.05% sulfur, by weight, fuel oil, and good combustion practices shall be employed to control all pollutants.

These emissions units are not subject to continuous assurance monitoring (CAM) because the NO_X CEMS is used for continuance compliance determination. Thus no CAM plan is included in this permit.

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

Based on the Title V permit revision application received on October 31, 2003, this facility is not a major source of hazardous air pollutants (HAPs). The facility holds ORIS codes **0564** and **55821** under the Acid Rain Program.

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Electric Generator No. 1
-002	Fossil Fuel Fired Steam Electric Generator No. 2
-003	Auxiliary Boiler
-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
-025	Combined-Cycle Combustion Turbine
-026	Combined-Cycle Combustion Turbine
-028	Distillate Fuel Oil Storage Tank

Unregulated Emissions Units and/or Activities
-017 Material Handling
-018 Fuel Storage Tanks
-019 Water Treatment
-020 Unconfined Emissions
-027 Mechanical Draft Cooling Tower

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

<u>These documents are provided to the permittee for information purposes only:</u>
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Statement of Basis

<u>These documents are on file with the permitting authority:</u>

Phase II Acid Rain Part Application signed by the Designated Representative on 04/15/02.
Title V Permit Revision Application received on 10/31/03.
Phase II NO_x Acid Rain Application/Compliance Plan (Revised) received August 17, 1999.
DRAFT Title V Air Operations Permit clerked on January 8, 2004.

<u>These documents are on file with the USEPA:</u>

The Responsible Official has certified that the Risk Management Plan was submitted to the RMP Reporting Center.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4., F.A.C.]

4. 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.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), 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 DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:

Cashier
Department of Community Affairs
State Emergency Response Commission
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents 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)(a), F.A.C.]

8. The following reasonable precautions shall be taken to prevent emissions of unconfined particulate matter at this facility on an as-needed basis:

- Paving and maintenance of roads, parking areas, and yards,
- Chemical (dust suppressants) or water application to unpaved roads, and unpaved yard areas,
- 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,
- Landscaping or planting of vegetation,
- Regular mowing of grass and care of vegetation,
- Confining abrasive blasting where possible,
- Limiting access to plant property by unnecessary vehicles, and
- Additional, or alternative activities, or other techniques to minimize unconfined PM emissions.

[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the Title V permit revision application received October 31, 2003.]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition **51.** of Appendix TV-4, Title V Conditions).}

11. The permittee shall submit all compliance-related notifications and reports required of this permit to the Central District Office:

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155, Fax: 404/562-9163

13. BACT Determination. In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes.
[40 CFR 52.21(j); 40 CFR 51.166(j); Rule 62-4.070 F.A.C.; and 0950137-002-AC, Specific Condition 7., Section II.]

14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following Regulated Emissions Units.

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator # 1
-002	Fossil Fuel Fired Steam Generator # 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 and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

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 and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Each boiler/steam generator, units #1 and #2, drives a turbine generator and both units have an individual 550 foot exhaust stack. 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%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Combustion Engineering.

Each boiler/steam generator, 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.**

{Permitting note(s): 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.; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD); and Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT). 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.}

The following specific conditions apply to the emissions units listed above:

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

A.1. Capacity. The maximum permitted heat input rate for Unit No. 1 and 2 is 4286 MMBTU/hr. Testing of emissions shall be conducted with the emissions unit operating at 90 to 100 percent of the maximum permitted heat input rate. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}
[Rule 62-4.160(2), and Rule 62-297.310(2), F.A.C.]

A.2. Methods of Operation - Fuels. Coal is permitted to be fired in Units No. 1 and 2. Coal shall not be burned in the unit unless both the electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 C.F.R. 60.46a. The fuel oil to be fired in Units 1 and 2 and the auxiliary boiler shall be primarily "new oil", which means an oil which has been refined from crude oil and has not been used. On-site generated lubricating oil and used fuel oil which meets the requirements of 40 CFR 266.40 may also be burned. Landfill gas from the Orange County Landfill and Natural gas as supplied by commercial pipeline may be burned in Unit No. 1 and 2.
[Rules 62-4.070(3), 62-4.160(2), 62-210.200, and 62-213.440(1), F.A.C., PSD-FL-084]

A.3. Methods of Operation - 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).
[Rule 62-4.070(3), F.A.C., 40 CFR 60.40a, and Permit No. PSD-FL-084]

A.4. Hours of Operation. Units No. 1 & 2 are allowed to operate continuously (i.e., 8760 hrs./yr.).
[Rule 62-210.200, F.A.C., Definitions (PTE)]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **A.5.** through **A.24.** are based on the specified averaging time of the applicable test method.}

A.5. Particulate matter emissions from Unit No. 1 shall not exceed 0.03 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. Particulate matter emissions from Unit No. 2 shall not exceed 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.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(a); 40 CFR 60.46a(a); 40 CFR 60.46a(c)]

A.6. Based on the maximum permitted heat input rate listed in Specific Condition A.1., the particulate matter emissions from Unit No. 1 shall not exceed 124.1 lbs/hour and 543.5 tons/year. The particulate matter emissions from Unit No. 2 shall not exceed 85.7 lbs/hr and 375.4 tons/year.
[PSD-FL-084 and Rule 62-296.700(4)(b)1., F.A.C.]

A.7. Particulate matter emissions from Units No. 1 and 2 when combusting liquid fuel (No. 6 fuel oil) shall not exceed 0.03 lb/million Btu and 30 percent of potential combustion concentration (70 percent reduction).
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(b)(1)]

A.8. Visible emissions from Units No. 1 and 2 shall not exceed 20 (twenty) percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 (twenty-seven) percent opacity.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(b)]

A.9. Sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.2 lb/million Btu (30 day rolling average) heat input or 1.2 lb/million Btu (2 hour emission rate) heat input. Additionally, sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.14 lb/million Btu (3-hr average) heat input (4886 lbs/hr and 21,400 tons/year) and 10 percent of the potential combustion concentration (90 percent reduction) or 30 percent of the potential combustion concentration (70 percent reduction) when emissions are less than 0.60 lb/million Btu heat input.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1) and (2); PSD-FL-084]

A.10. Sulfur dioxide emissions from Unit No. 2 when combusting solid fuel shall not exceed 0.25 lb/million Btu (30 day rolling average) heat input; 0.67 lb/million Btu (24 hour emission rate) heat input or 0.85 lb/million Btu (3 hour emission rate) heat input. This corresponds to 3643 lbs/hr and 4,693 tons/year emission rate.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1); PSD-FL-084]

A.11. Sulfur dioxide emissions from Units No. 1 and 2 when combusting liquid fuel (No. 6 fuel oil) shall not exceed 0.80 lb/million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction).
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(b)(1)]

A.12. Compliance with a sulfur dioxide emission limitation and percent reduction requirements are both determined on a 30-day rolling average basis.
[Rule 62.204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(g)]

A.13. When different fuels are combusted simultaneously in Unit No. 1, the applicable standard of sulfur dioxide is determined by proration using the following formula:
(1) 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

(2) 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

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(h); PSD-FL-084]

A.14. When different fuels are combusted simultaneously in Unit No. 2, the applicable standard of sulfur dioxide is determined by proration using the following formula:
(1) 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

(2) 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 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

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(h); PSD-FL-084]

A.15. Nitrogen dioxide emissions from Unit No. 1 when combusting bituminous coal shall not exceed 0.60 lb./million Btu heat input (30 day rolling average) nor 0.46 lb./million Btu heat input on an annual average. Nitrogen dioxide emissions from Unit No. 2 when combusting bituminous coal shall not exceed 0.17 lb./million Btu heat input. Nitrogen dioxide emissions from Units No. 1 and 2 when combusting liquid fuel shall not exceed 0.30 lb/million Btu heat input. These emission limits are based on a 30-day rolling average. These standards apply at all times except during periods of startup, shutdown, or malfunction. Ammonia slip from the NOx control system

shall be limited to less than 30 ppmv, uncorrected. An ammonia monitoring protocol shall be submitted to EPA for review and approval prior to the operation of Unit 2.
{Permitting note: In accordance with 40 C.F.R. 70.6(a)(1)(ii), "where an applicable requirement of the Act is more stringent than an applicable requirement of the regulations promulgated under title IV of the Act, both provisions shall be incorporated in the permit and shall be enforceable by the Administrator." Unit 1 is required to meet the more stringent NOx limit of 0.46 pounds per MMBtu in addition to the 0.60 pounds per MMBtu PSD NOx limit.}
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(a); 40 CFR 60.46a(b); 40 CFR 60.46a(c)]

A.16. When liquid and solid fuels are combusted simultaneously in Unit No. 1, the applicable standard for nitrogen dioxides 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
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(c)]

A.17. When liquid and solid fuels are combusted simultaneously in Unit No. 2, the applicable standard for nitrogen dioxides is determined by proration using the following formula:

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
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(c)]

A.18. Carbon monoxide (CO) emissions from Unit No. 2 shall not exceed 0.15 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, CO emissions shall not exceed 643 lb/hr (2816 TPY).
[PSD-FL-084]

A.19. Volatile Organic Compounds (VOC) emissions from Unit No. 2 shall not exceed 0.015 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, VOC emissions shall not exceed 64 lb/hr (282 TPY).
[PSD-FL-084]

A.20. Sulfuric acid mist (H_2SO_4) emissions from Unit No. 2 shall not exceed 0.033 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, H_2SO_4 emissions shall not exceed 140 lb/hr (613 TPY).
[PPS PA 81-14/SA1]

A.21. Beryllium (Be) emissions from Unit No. 2 shall not exceed $5.2x10^{-6}$ lb./million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Be emissions shall not exceed 0.022 lb./hr (0.1 TPY).
[PPS PA 81-14/SA1]

A.22. Mercury (Hg) emissions from Unit No. 2 shall not exceed 1.1×10^{-5} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Hg emissions shall not exceed 0.046 lb/hr (0.2 TPY).
[PPS PA 81-14/SA1]

A.23. Lead (Pb) emissions from Unit No. 2 shall not exceed 1.5×10^{-4} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Pb emissions shall not exceed 0.64 lb/hr (2.8 TPY).
[PPS PA 81-14/SA1]

A.24. Fluorides (Fl) emissions from Unit No. 2 shall not exceed 4.2×10^{-4} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Fl emissions shall not exceed 1.8 lb/hr (7.9 TPY).
[PPS PA 81-14/SA1]

Compliance Provisions

A.25. The sulfur dioxide emission standards in specific conditions A.9., A.10., A.11., A.13 and A.14., apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the following procedures in specific condition A.26. are implemented.
[Rule 62-296.800(7)(b)2., F.A.C.; 40 CFR 60.46a(c)]

A.26. During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Operating a *spare* flue gas desulfurization system module. The Department may at their discretion require the permittee within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements of specific conditions A.9., A.10., A.11., A.13 and A.14. for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,
(ii) The affected facility is operating at the maximum heat input rate,
(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and
(iv) The owner or operator has given the Department at least 30 days notice of the date and period of time over which the demonstration will be performed.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(d)]

A.27. Compliance with the sulfur dioxide emission limitations and percentage reduction requirements in specific conditions A.9., A.10., A.11., A.13 and A.14., and the nitrogen oxides emission limitations in specific conditions A.15., A.16 and A.17., is based on the *average emission rate* for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-day

average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(e)]

A.28. Compliance is determined by calculating the arithmetic average of all hourly *emission rates* for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup and shutdown (SO_2 & NO_X), simultaneous combustion of different fuels (SO_2 & NO_X), malfunction (NO_X only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days. Compliance with the limits determined from specific conditions A.13., A.14., A.15. and A.16. (above) shall be determined by calculating the arithmetic average of all hourly *emission rates* for SO_2 and NO_X from any operating hours for the 30 prior boiler operating days where simultaneous combustion of different fuels occurred.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(g)]

A.29. If the permittee has not obtained the minimum quantity of emission data as required in the following emission monitoring specific conditions A.30. through A.39, compliance of Units No. 1 and 2 with the sulfur dioxide and nitrogen oxides standards for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19, *Determination of Compliance When Minimum Data Requirement Is Not Met.*
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(h); 40 CFR 60, Appendix A, Method 19]

Emissions Monitoring

A.30. 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(7)(b)2., F.A.C.; 40 CFR 60.47a(a), PSD-FL-084]

A.31. 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:
(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
(2) 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.31.(1).
(3) 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 SO2 in the flue gas (or 70% for mass SO2 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.
[PSD-FL-084, Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(b); 40 CFR 60, App. A, Mth.19]

A.32. 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(7)(b)2., F.A.C.; 40 CFR 60.47a(c)]

A.33. 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.
[PSD-FL-084, Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(d)]

A.34. The continuous monitoring systems required in specific conditions A.31., A.32., and A.33., shall be operated and record data during all periods of operation of Units No. 1 and 2 including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(e)]

A.35. The permittee shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the permittee shall supplement emission data with other monitoring systems approved by the Department, or the reference methods and procedures as described in Specific Condition **A.37.**
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a (f)]

A.36. The 1-hour averages required under 40 CFR 60.13(h), *Monitoring Requirements*, are expressed in lbs/million Btu heat input and used to calculate the average emission rates required in specific conditions A.27. and A.28. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b), *Monitoring Requirements*. At least two data points must be used to calculate the 1-hour averages.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(g)]

A.37. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in Specific Condition **A.35.**, the permittee shall use the following reference methods and procedures. Acceptable alternative methods and procedures are given in Specific Condition **A.38.**

(1) Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in lb/million Btu heat input.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(h); 40 CFR 60, Appendix A, Methods 3B, 6, 7, and 19]

A.38. The permittee shall use the following methods and procedures to conduct the monitoring system performance evaluations required under *40 CFR 60.13(c), Monitoring Requirements,* and the calibration checks required under *40 CFR 60.13(d), Monitoring Requirements*. Acceptable alternative methods and procedures are given in specific condition A.39.

(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_x concentrations

(2) SO_2 or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under 40 CFR 60 Appendix B, Performance Specification 2.

(3) The span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Liquid............................	500
Solid..............................	1,000
Combination....................	500y + 1,000z

where:
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under the preceding specific condition A.38.(3) for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions oil fuel, alone or in combination with non-fossil fuel, the span value of the fuel fired.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(i); 40 CFR 60.13; 40 CFR 60 Appendix A, Methods 3B, 6, and 7; 40 CFR 60 Appendix B, Performance Specification 2.]

A.39. The permittee may use the following as alternatives to the reference methods and procedures specified in conditions **A.37.** and **A.38.**:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If

Method 6A or 6B is used under specific condition A.38., the conditions under 40 CFR 60.46(d)(1) apply; these conditions do not apply under specific condition A.37.
(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.
(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.
(4) For Method 3B, Method 3A may be used.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(j); 40 CFR 60.46(d)(1), 40 CFR 60 Appendix A, Methods 3, 3A, 3B, 6, 6A, 6B, 6C, 7, 7A, 7C, 7D, and 7E]

Compliance determination procedures and methods

A.40. In conducting the performance tests required in *40 CFR 60.8*, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in conditions A.41. through A.45., except as provided in *40 CFR 60.8(b)*. *40 CFR 60.8(f)* does not apply to specific conditions A.42 and A.43. for SO_2 and NO_X. Acceptable alternative methods are given in specific condition A.45. Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.
[Rule 62-204.800(7)(b)2., 62-210.300(2)(a)1., F.A.C.; 40 CFR 60.48a(a); 40 CFR 60.8]

A.41. The permittee shall determine compliance with the particulate matter standards in specific conditions A.5., A.6., A.7 and A.8 as follows:
(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.
(2) For the particulate matter concentration, Method 5B shall be used after **wet** FGD systems.
(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).
(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each traverse point.
(3) Method 9 and the procedures in *40 CFR 60.11* shall be used to determine opacity.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(b); 40 CFR 60.11, 40 CFR 60 Appendix A, Methods 1, 3B, 5B, 9, and 19]

A.42. The permittee shall determine compliance with the SO_2 standards in specific conditions A.9., A.10., A.11., A.13 and A.14. as follows:
(1) The percent of potential SO_2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_f)(100 - \%R_g)]/100$$

where:

$\%P_s$	=	percent of potential SO_2 emissions, percent.
$\%R_f$	=	percent reduction from fuel pretreatment, percent.
$\%R_g$	=	percent reduction by SO_2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%R_f) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO_2 reduction (%R_g of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring systems specified in conditions A.31. and A.33. shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a (c); 40 CFR 60 43a; 40 CFR 60.47a(b) and (d); 40 CFR 60 Appendix A, Method 19]

A.43. The permittee shall determine compliance with the NO_X standards in Specific Conditions A.15., A.16. and A.17. as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the NO_X emission rate.

(2) The continuous monitoring systems specified in specific conditions A.32. and A.33. shall be used to determine the concentrations of NO_x and CO_2 or O_2.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(d); 40 CFR 60.44a; 40 CFR 60.47a(c); 40 CFR 60.47a(d)]

A.44. The permittee shall determine initial compliance with the CO, VOC, Be, Hg, Pb and Fl standards in specific conditions A.18., A.19., A.21., A.22., A.23., and A.24 respectively as follows:

(1) EPA Method 10 for CO emissions.

(2) EPA Method 18, 25, 25A or 25B for VOC emissions.

(3) EPA Method 104 for Be emissions.

(4) EPA Method 101A or 108 for Hg emissions.

(5) EPA Method 12 or 101A for Pb emissions

(6) EPA Method 13A or 13B for Fl emissions.

The permittee shall conduct annual compliance tests for particulates, NO_x, SO_2 and visible emissions.

[PPS PA 81-14/SA1]

A.45. The permittee may use the following as alternatives to the reference methods and procedures specified in condition A.41:

(1) For Method 5 or 5B, Method 17 may be used at Units No. 1 and 2 if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of *40 CFR 60.46(d)(1)*. The CO_2 shall be determined in the same manner as the O_2 concentration.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(e); 40 CFR 60.46(d)(1); 40 CFR 60 Appendix A, Methods 5, 5B, 17, and 19]

Reporting Requirements

A.46. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be submitted to the Department.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(a)]

A.47. For sulfur dioxide and nitrogen oxides the following information shall be reported to the Department for each 24-hour period.
(1) Calendar date.
(2) The average sulfur dioxide and nitrogen oxide emission rates (lb/million Btu heat input) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.
(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.
(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification or not obtaining sufficient data; and description of corrective actions taken.
(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup and shutdown (SO_2 & NO_X), simultaneous combustion of different fuels (SO_2 & NOx), malfunction (NO_X only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, simultaneous fuel combustion, malfunction, or emergency conditions.
(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
(7) Identification of times when hourly averages have been obtained based on manual sampling methods.
(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with 40 CFR 60 Appendix B, Performance Specifications 2 or 3.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(b); 40 CFR 60 Appendix B]

A.48. If the minimum quantity of emission data, as required by the emission monitoring specific conditions A.30. through A.39., is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Specific Condition **A.29.** shall be reported to the Administrator for that 30-day period:
(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.
(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.
(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.
(4) The applicable potential combustion concentration.
(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(c); 40 CFR 60 Appendix A, Method 19]

A.49. If any sulfur dioxide standards under specific conditions **A.9., A.10., A.11., A.13.** or **A.14.** are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under specific condition A.26. were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J or lb/MMBtu) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(d); 40 CFR 60.43a; 40 CFR 60.46a(d)]

A.50. If fuel pretreatment credit is claimed toward the sulfur dioxide emission standards in specific conditions A.9., A.10., A.11., A.13. or A.14., the permittee shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of specific condition A.42. and Method 19 (Appendix A of 40 CFR 60); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(e), 40 CFR 60.48a(c)]

A.51. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(f)]

A.52. The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(g)]

A.53. For the purposes of the reports required under *40 CFR 60.7*, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under specific condition A.8. Opacity levels in excess of the applicable opacity standard and the date of such excesses shall be submitted to the Administrator each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(h)]

A.54. The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Department for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(i)]

A.55. 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 two years.
[PSD-FL-084]

Subsection B. This section addresses the following Regulated Emissions Unit.

E.U. ID No.	Brief Description
-003	Auxiliary Boiler

The auxiliary boiler is designated as Unit No. 3. The unit is a Babcock & Wilcox Model No. FM-2919 boiler. It is fired primarily with "new oil", which means an oil which has been refined from crude oil and has not been used. Only No. 2 fuel oil can be burned in the auxiliary boiler. This auxiliary boiler serves both Unit No. 1 and 2 boiler/steam generators.

{Permitting note: This emission unit is regulated under Rule 62-210.300, F.A.C., Permits Required.}

The following conditions apply to the Emission Unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Capacity. The maximum permitted heat input rate for Unit No. 3 is 83 MMBtu/hour.

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}
[Rule 62-210.200(PTE), F.A.C.]

B.2. Methods of Operation. Fuel. The auxiliary boiler shall be fired on No. 2 fuel oil having a sulfur content less than 0.5 percent, by weight.
[Rule 62-4.160(2), F.A.C., Construction application request]

B.3. Hours of Operation. The emission unit may operate up to 150 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Condition **B.4.** are based on the specified averaging time of the applicable test method.}

B.4. Emissions from the auxiliary boiler for burning No. 2 fuel oil shall not exceed the allowable emission limits listed in the following table:

Allowable Emission Limits

Pollutant	lb/MMBtu
PM	0.015
SO_2	0.51
NO_x	0.16
Visible Emissions	20% Opacity

[Rule 62-4.160(2), F.A.C., and PSD-FL-084]

B.5. Compliance testing for PM, SO_2, NO_x, and visible emissions is not required if the unit operates for less than 400 hours annually.
[Rule 62-297.310(7)(a), F.A.C.]

B.6. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[PSD-FL-084]

Record keeping and Reporting Requirements

B.7. Documentation of the type, quantity, and analysis of the fuel oil used/received is required.
[PSD-FL-084]

B.8. Documentation on operating hours shall be kept in order to ensure that the source is operating less than 150 hours per year and is exempted from compliance testing as per specific condition B.5.
[PSD-FL-084, Rule 62-297.310(7)(a), F.A.C.]

Subsection C. This section addresses the following Regulated Emissions Units.

E.U. ID 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
-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

Descriptions

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 emissions generated by silo loading and unloading to a tanker truck is controlled by baghouses in addition to reasonable precautions. These units are subject to the applicable requirements under 40 C.F.R. 60 Subpart Y - Standards of Performance for Coal Preparation Plants, since Stanton has coal processing and conveying equipment (including breakers and crushers) and the facility commenced construction after October 24, 1974, per 40 C.F.R. §60.250.
{Permitting note: The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.}

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Hours of Operation. Fly Ash Silos are each allowed to operate continuously (i.e., 8760 hrs./yr.)
[Rule 62-210.200, F.A.C., Definition (PTE)]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Condition **C.2.** are based on the specified averaging time of the applicable test method.}

C.2. 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.
[PPS PA 81-14/SA1]

C.3. 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.

[PSD-FL-084]

Test Methods and Procedures

C.4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the permittee shall have formal compliance test conducted on each silo baghouse for opacity. Additionally, each baghouse shall be visually inspected on a daily basis to ensure that emissions are not visible. Records shall be maintained documenting that such inspections took place. Should emissions from a baghouse be visible, corrective action should be undertaken as well as conducting a Method 9 V.E. Records should include color, duration, and density of the plume of any abnormal visible emissions detected, as well as the cause and corrective action taken for any abnormal visible emissions.
{Permitting note: It is presumed that the threshold of visibility for opacity is equal to 5%.}
[Rule 62-297.310(7)(a)4., F.A.C., Rule 62-213.440, F.A.C.]

C.5. Compliance with the opacity limit listed in **C.2.** will be determined by EPA Reference Method 9.
[PPS PA 81-14/SA1]

Subsection D. Common Conditions.

The following conditions apply to the Emissions Units ID -001, -002, -025, and -026:

40 CFR 60 Subpart A

D.1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

Notification and Recordkeeping

D.2. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:
(1) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
[40 CFR 60.7(a)(4)]

D.3. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b)]

D.4. Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
[40 CFR 60.7(c)(1), (2), (3), and (4)]

D.5. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.
(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.
{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance} (electronic file name: figure1.doc)
[40 CFR 60.7(d)(1) and (2)]

D.6. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to

the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)(1)]

D.7. Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

Performance Tests

D.8. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
[40 CFR 60.8(c)]

Compliance with Standards and Maintenance Requirements

D.9. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
[40 CFR 60.11(a)]

D.10. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
[40 CFR 60.11(b)]

D.11. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
[40 CFR 60.11(c)]

D.12. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

D.13. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11(e)(5)]

Circumvention

D.14. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

Monitoring Requirements

D.15. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
[40 CFR 60.13(a)]

D.16. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.
(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 60.8 and as described in 40 CFR 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 60.8 is conducted.
[40 CFR 60.13(c)(1)]

D.17. (1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.
[40 CFR 60.13(d)(1) and (2)]

D.18. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
[40 CFR 60.13(e)(1) and (2)]

D.19. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.
[40 CFR 60.13(f)]

D.20. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.
[40 CFR 60.13(g)]

D.21. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

The following conditions apply only to the Emissions Units ID -001 and -002:

Additional Limitations for On-Specification Used Oil

D.22. 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:

a. immediately notify the Central District Office in Orlando;
b. provide the analytical results for the above parameters; and
c. 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]

Subsection E. This section addresses the following Regulated Emissions Units.

E.U. ID No.	Brief Description
-025	Combined-Cycle Combustion Turbine
-026	Combined-Cycle Combustion Turbine

These emissions units include two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel fuel oil and equipped with evaporative coolers on the inlet air system, two supplementary fired heat recovery steam generators (HRSGs), each with a 160 ft. stack, and one steam turbine-electrical generator rated at approximately 300 MW. Units 25 and 26 have a total nominal capacity of 640 MW and will achieve approximately 700 megawatts during extreme winter peaking conditions.

The combustion turbines are equipped with Dry Low NO_X combustors and a selective catalytic reduction (SCR) system in order to control NO_X emissions to 3.5 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. Pipeline quality natural gas, 0.05% sulfur fuel oil, by weight, and good combustion practices shall be used to control all pollutants.

The combustion turbines are subject to the requirements of Phase II of the federal Acid Rain Program. These units hold ORIS code **55821**. Unit 025 commercial start date was April 28, 2003, and Unit 026 commercial start date was April 28, 2003.

These emissions units are not subject to compliance assurance monitoring (CAM) because the NO_X CEMS is used for continuance compliance determination. Thus, no CAM plan is included in this permit.

The following conditions apply to the emission units listed above:

General

E.1. NSPS Requirements: Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

a. Subpart A, General Provisions (see Specific Condition **E.2.**)

b. Subpart GG, Standards of Performance for Stationary Gas Turbines. [See attached Appendix GG.]

[0950137-002-AC, Specific Condition 2.]

E.2. These emission units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

- 40 CFR 60.7, Notification and Recordkeeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

[0950137-002-AC, Specific Condition 4.]

E.3. Each emissions unit shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Compliance determination for BACT standards shall comply with all applicable provisions of 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.
[0950137-002-AC, Specific Condition 5.]

E.4. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices of pollution control equipment shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment.
[Rule 62-4.070(3), F.A.C.; and 0950137-002-AC, Specific Condition 14.]

E.5. Circumvention. The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.
[Rule 62-210.650, F.A.C.; and 0950137-002-AC, Specific Condition 15.]

Control Technology

E.6. Dry Low NO_X (DLN) combustors and water injection capability are installed on each stationary combustion turbine. The permittee has installed a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition **E.14.** Additionally, space is provided for the installation of oxidation catalysts.
[Rules 62-4.070 and 62-212.400, F.A.C.; and 0950137-002-AC, Specific Condition 18.]

E.7. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions **E.14.** through **E.18.**
[Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR60.40a(b); and 0950137-002-AC, Specific Condition 19.]

E.8. Drift eliminators are installed on the cooling tower to reduce PM/PM_{10} emissions. A certification letter, following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.
[0950137-002-AC, Specific Condition 20.]

Essential Potential to Emit (PTE) Parameters

E.9. Maximum allowable hours of operation for each CT/HRSG Emissions Unit are 8760 hours per year while firing natural gas. Fuel oil firing is permitted for 1000 hours during any consecutive 12-month period in each CT.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); 0950137-002-AC, Specific Condition 16.]

E.10. Combustion Turbine Capacity. 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.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and 0950137-002-AC, Specific Condition 10.]

E.11. 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) at any temperature or under any scenario.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and 0950137-002-AC, Specific Condition 11.]

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

E.12. Fuels. Only pipeline natural gas or (up to) 1000 hours per year of 0.05%, by weight, distillate fuel oil shall be fired in each CT emissions unit. Only natural gas shall be fired in each duct burner.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and 0950137-002-AC, Specific Condition 9.]

E.13. Simple Cycle Operation. The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.
[0950137-002-AC, Specific Condition 17.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **E.14.** through **E.18.** are based on the specified averaging time of the applicable test method.}

E.14. Nitrogen Oxides (NO_X) Emissions.

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas, shall not exceed 3.5 ppmvd @15% O_2 on a 3-hour block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS).
- The emissions of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil shall not exceed 10.0 ppmvd @15% O_2 on a 3-hour block average. Compliance shall be determined by the continuous emission monitor (CEMS).
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition **E.23.** for compliance procedures).

- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions **E.22.** and **E.36.**

[BACT Determination; Rules 62-4.070, 62-204.800(7), 62-212.400, and 62-4.070, F.A.C.; and 0950137-002-AC, Specific Condition 21.]

E.15. 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 RATA testing. Within 24 months of the date of completion of initial testing, the applicant shall either have installed oxidation catalyst in each CT/HRSG or forfeit its right to do so with the pre-determined (BACT) emission limits specified below.

In the event that an oxidation catalyst is installed for any reason in either CT/HRSG pair within 24 months of the date of completion of initial testing, the limits for CO and VOC shall be 5 ppmvd and 3 ppmvd (respectively) to be demonstrated by stack testing during power augmentation and duct burner firing (both initial and annual tests are required).
[BACT Determination; Rule 62-212.400, F.A.C.; and 0950137-002-AC, Specific Condition 22.]

E.16. Volatile Organic Compounds (VOC) Emissions. Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) shall not exceed 2.7 ppmvd @15% O_2 with the CT firing fuel oil or 6.3 ppmvd @15% O_2 with the CT firing natural gas (with maximum duct burner firing and operating in power augmentation mode); to be demonstrated by *initial* stack tests using EPA Method 18, 25 and/or 25A.
[BACT Determination; Rule 62-212.400, F.A.C.; and 0950137-002-AC, Specific Condition 23.]

E.17. Sulfur Dioxide (SO_2) Emissions. SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot) and up to 1000 hours per consecutive 12-month period of 0.05% sulfur, by weight, fuel oil. Compliance with these fuel limits in conjunction with implementation of the attached Appendix GG will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner and the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-025 and EU-026 to approximately 134 tons per year.
[BACT Determination; 40 CFR 60 Subpart GG; Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.; and 0950137-002-AC, Specific Condition 24.]

E.18. PM/PM_{10} and Visible Emissions (VE). Visible emissions shall not exceed 10 percent opacity from the stack in use.
[BACT Determination; Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.; and 0950137-002-AC, Specific Condition 25.]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

E.19. Excess emissions resulting from startup, shutdown, fuel switching, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period. During any 24-hour period in which an hour of start-up or shutdown occurs, the following alternative emission limits shall apply on the basis of a 24-hour rolling average:

a) An alternative NO_X limit of 127 lb/hr shall apply if natural gas is the exclusively fired fuel;
b) An alternative NO_X limit of 370 lb/hr shall apply if any fuel oil is fired; and,
c) An alternative CO limit of 155 lb/hr firing either natural gas or fuel oil.

The 24-hour averages shall be based on all available data excluding calibration data. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period.
[BACT Determination; Rule 62-210.700, F.A.C.; and 0950137-002-AC, Specific Condition 26., modified on May 16, 2003.].

E.20. Excess emissions 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.
[0950137-002-AC, Specific Condition 27.]

E.21. Excess Emissions Report. If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office 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. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions **E.31.** through **E.35.**, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Conditions **E.14.** through **E.18.**
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 (1998 version); and 0950137-002-AC, Specific Condition 28.]

Test Methods and Procedures

E.22. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.
[0950137-002-AC, Specific Condition 29.]

E.23. *Initial (I)* performance tests shall be performed by the deadlines in Specific Condition **E.22.** *Initial* tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or addition of oxidation catalyst (or change of combustors, if specifically requested by the DEP on a case-by-case basis). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement) shall be conducted a) while firing natural gas with maximum duct burner heat input as well as maximum power augmentation and b) while firing fuel oil at the maximum heat input; Initial test for compliance with 40 CFR 60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." *Initial* test only.
- Method CTM-027 for ammonia slip (I, A) to be completed simultaneously with NO_X compliance testing.

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition **E.35.**

[0950137-002-AC, Specific Condition 30.]

E.24. Continuous compliance with the CO and NO_X emission limits. Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hourly average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition **E.31.** further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition **E.21.**
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT; and 0950137-002-AC, Specific Condition 31.]

E.25. Compliance with the SO_2 and PM/PM_{10} emission limits. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, the applicant is responsible for ensuring that the procedures outlined in attached Appendix GG are complied with.
[0950137-002-AC, Specific Condition 32.]

E.26. Compliance with CO emission limit. An *initial* and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75 and may substitute for the annual CO stack testing requirement.
[0950137-002-AC, Specific Condition 33.]

E.27. Compliance with the VOC emission limit. An *initial* test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required (see Specific Condition **E.15.** for exception).
[0950137-002-AC, Specific Condition 34.]

E.28. Testing procedures. Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. inlet temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.
[0950137-002-AC, Specific Condition 35.]

E.29. Test Notification. The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.
[0950137-002-AC, Specific Condition 36.]

E.30. Special Compliance Tests. The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, odors or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.
[0950137-002-AC, Specific Condition 37.]

E.31. Test Results. Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run.
[Rule 62-297.310(8), F.A.C.; and 0950137-002-AC, Specific Condition 38.]

Monitoring Requirements

E.32. Continuous Monitoring System. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NO_X shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly 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). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. The permittee may use the inlet SCR NO_X monitor as a backup analyzer in determining excess emissions during startup. If the CEM system 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 CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. However, in the event that the permittee maintains 95% or greater availability of the continuous emission monitoring systems used for determining NO_X emissions compliance for the previous quarter, then compliance with the emission limits for NO_X shall be based on 3 valid consecutive hours of data for a 3-hour block average. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall be between or inclusive of the values of 10 and 20 ppm, and the span for the upper range shall be between or inclusive of the values of 200 and 250 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. 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 semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and 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. The CO monitor shall be a dual range monitor. The span for the lower range shall be between or inclusive of the values of 20 and 30 ppm, and the span for the upper range shall be between or inclusive of the values of 500 and 1000 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60. NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. 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.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur. Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.
[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].
[Rules 62-4.070(3) and 62-212.400., F.A.C.; BACT Determination; and 0950137-004-AC, Specific Condition 41., modified on May 16, 2003.]

E.33. Continuous Monitoring System Reports. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.
[0950137-002-AC, Specific Condition 42.]

E.34. Determination of Process Variables.

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; and 0950137-002-AC, Specific Condition 43.]

E.35. Subpart Da Monitoring and Recordkeeping Requirements. The permittee shall comply with all applicable requirements of 40 CFR 60 Subpart Da.
[40 CFR 60, Subpart Da; and 0950137-002-AC, Specific Condition 44.].

E.36. Selective Catalytic Reduction System (SCR) Compliance Procedures.

- An annual stack emission 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 on as defined in Specific Condition **E.14.** The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.

- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.

- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.

- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.

- In the event of a complaint or concern by an inspector, the permittee shall be capable of making an instantaneous measurement using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system to determine ammonia slip. This determination shall not be used as a compliance method but only as an indicator to determine if a special compliance test is needed to demonstrate NO_X and ammonia slip requirements of the permit. The calculation procedure shall be provided with the CEM monitoring plan required by 40 CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

<u>Ammonia slip @ 15%O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D</u>, where: A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)

B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)
C = change in measured NO_X (ppmv@15%O_2) across catalyst
D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

[Note: exhaust gas flow rate may be back calculated using heat input and F factor.]

- The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.

- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

[0950137-002-AC, Specific Condition 45.]

<u>Recordkeeping and Reporting Requirements</u>

E.37. Records. All measurements, records, and other data required to be maintained by the applicant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

- The applicant will be required to maintain records indicating the daily hours of operation of each CT/HRSG unit. These records shall specify which type of fuel is being combusted and the records shall be available for review at the site. Each calendar month, a compilation of the hours of operation for each CT/HRSG unit combusting fuel oil shall be made and totalized for the most recent consecutive 12-month period. Each AOR submitted by the applicant shall include a compilation of each consecutive 12-month period during the preceding calendar year.

[0950137-002-AC, Specific Condition 39.]

E.38. Compliance Test Reports. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.
[0950137-002-AC, Specific Condition 40.]

E.39. Annual Reports. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District Office by March 1st of each year.
[0950137-002-AC, Specific Condition 12., Section II.]

E.40. Quarterly Reports. Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.
[0950137-002-AC, Specific Condition 14., Section II.]

Subsection F. This section addresses the following Regulated Emissions Unit.

E.U. ID No.	Brief Description
-028	Distillate Fuel Oil Storage Tank

This fuel storage unit, consisting of a 1.86 million gallon distillate fuel oil storage tank (Unit 028), shall comply with all applicable provisions of 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.
[0950137-002-AC, Specific Condition 7.]

The following conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200, F.A.C., Definitions - (PTE).]

Recordkeeping Requirements

F.2. The permittee shall maintain records on site for storage vessel identification number 028 to include the date of construction, the material storage capacity, and type of material stored for the life of this storage vessel.
[40 CFR 60.116b(b).]

Section IV. This section is the Acid Rain Part.

Operated by: Orlando Utilities Commission and OUC/KUA/FMPA/Southern Company – Florida, LLC
ORIS codes: **0564** and **55821**

Subsection A. This subsection addresses Acid Rain, Phase II.

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

E.U. ID No.	Description
-001	Fossil Fuel Fired Steam Generator No. 1
-002	Fossil Fuel Fired Steam Generator No. 2
-025	Combined-Cycle Combustion Turbine
-026	Combined-Cycle Combustion Turbine

A.1. The 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 acid rain units must comply with the standard requirements and special provisions set forth in the application listed below:

a. DEP Form No. 62-210.900(1)(a), dated 04/16/01, signed by the Designated Representative on 04/15/02.

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

A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NOx) limitations for each Acid Rain unit are:

E.U. ID No.	EPA I.D.	Year	2000	2001	2002	2003	2004
-001	1	SO_2 allowances, under Table 2 of 40 CFR 73	11290*	11290*	11290*	11290*	11290*
		NO_X limit	0.46⁺ lb./mmBtu	0.46⁺ lb./mmBtu	0.46⁺ lb./mmBtu	0.46⁺ lb./mmBtu	0.46⁺ lb./mmBtu
-002	2	SO_2 allowances, under Table 2 of 40 CFR 73	0*	0*	0*	0*	0*
		NO_X limit	0.17 lb./mmBtu	0.17 lb./mmBtu	0.17 lb./mmBtu	0.17 lb./mmBtu	0.17 lb./mmBtu
-025	25	SO_2 allowances to be determined by USEPA	N/A	N/A	N/A	N/A	0*
-026	26	SO_2 allowances to be determined by USEPA	N/A	N/A	N/A	N/A	0*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 of 40 CFR 73.
⁺This is an annual average.

A.3. Emission Allowances. 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 requirements 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 62-213.440(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), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: None.

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions – Applicable Requirements, F.A.C.]

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Revised Date(s)
-001	Fossil Fuel Steam Generation Unit #1	PPS PA 81-14 PSD-FL-084	12/15/82		12/24/97
-002	Pulverized Coal Fired Unit No. 2	PPS PA 81-14 PSD-FL-084	12/17/91 12/23/91		12/24/97
		0950137-001-AV	1/01/00	12/31/04	
-025 -026 -028	Combined-Cycle Combustion Turbine Combined-Cycle Combustion Turbine Distillate Fuel Oil Storage Tank	0950137-002-AC PSD-FL-313 PA81-14SA2	9/26/01	12/31/04	
-025 -026	Combined-Cycle Combustion Turbine Combined-Cycle Combustion Turbine	0950137-003-AC PSD-FL-313 PA81-14SA2	5/16/03	5/16/08	
-025 -026	Combined-Cycle Combustion Turbine Combined-Cycle Combustion Turbine	0950137-004-AC PSD-FL-313 PA81-14SA2	5/16/03	5/16/08	

ID Number Changes (for tracking purposes):

From: **Facility ID No.** 30ORL480137 To: **Facility ID No.** 0950137

Appendix U-1. List of Unregulated Emissions Units and/or Activities.

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

For those unregulated emissions units subject to the *General Visible Emissions Standard* at Rule 62-296.320(4)(b), F.A.C., then the provisions of Rule 62-210.700, F.A.C., *Excess Emissions*, are available for purposes of compliance.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

Emissions Unit	Description
-xxx	Surface Coating and Solvent Cleaning
-xxx	General Purpose Engines
-018	Fuel Storage Tanks
-xxx	Helper Cooling Towers
-xxx	Emergency Generators
-027	Mechanical Draft Cooling Tower

The Mechanical Draft Cooling Tower is not subject to a NESHAP because a chromium-based chemical treatment is not used.

[0950137-002-AC, Specific Condition 6.]

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

1	Lube Oil System Vents
2	Lube Oil Reservoir Tank
3	Oil Water Separators
4	Fixated Ash Disposal
5	Parts Washers/Degreasers
6	Waste Oil Storage Tanks
7	Lube Oil Storage Building
8	Portable Unleaded Gasoline Tank
9	Evaporation of non-hazardous boiler cleaning chemical
10	Sulfuric Acid Tanks

APPENDIX GG
NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES
[01950137-002-AC]

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NO_X CEMS. The "Y" values are approximately 10.0 for natural gas and 10.6 for fuel

oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit are more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel, which contains sulfur in excess of 0.8 percent by weight.

Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(1) Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NO_X CEMS shall be used to demonstrate compliance with the NO_X limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

(2) [Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is

greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NO_X emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NO_X monitor is required to demonstrate compliance with the standards of this permit. Data from the NO_X monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NO_X) shall be computed for each run using the following equation:

$$NO_X = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NO_X	=	emission rate of NO_X at 15 percent O2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NO_X concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NO_X monitor continuously correct NO_X emissions concentrations to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the BACT NO_X limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_X emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NO_X emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_X monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

<u>Department requirement</u>: The permit specifies sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

Table 1-1, Summary of Air Pollutant Standards and Terms

Orlando Utilities Commission — Permit No. **0950137-005-AV**

Stanton Energy Center — Facility ID No. **0950137**

E.U. ID Nos. — Brief Description

-001 — Fossil Fuel Fired Steam Generator #1

Pollutant Name	Fuel(s) *	Hours/ Year *	Allowable Emissions: Standards	Allowable Emissions: lb/ hour	Allowable Emissions: TPY	Equivalent Emissions: lb/hour **	Equivalent Emissions: TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	Coal F.O.	8760	0.03 lb/MMBtu 0.03 lb/MMBtu			128.6	563.2	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.5, A.6 A.7
Visible Emissions	Coal F.O.	8760	20% Opacity					Rule 62-204.800(7)(b)2, F.A.C.	A.8
Sulfur Dioxide	Coal F.O.	8760	1.14 lb/MMBtu 0.80 lb/MMBtu			4886	21,400	Rule 62.204.800(7)(b)2, F.A.C. Rule 62.204.800(7)(b)2, F.A.C.	A.9,Sec IV-A2 A.11
Nitrogen Oxide	Coal F.O.	8760	0.46 lb/MMBtu 0.30 lb/MMBtu			1971	8,635	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.15,Sec IV-A2 A.15

-002 — Fossil Fuel Fired Steam Generator #2

Pollutant Name	Fuel(s) *	Hours/ Year *	Allowable Emissions: Standards	Allowable Emissions: lb/ hour	Allowable Emissions: TPY	Equivalent Emissions: lb/hour **	Equivalent Emissions: TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	Coal F.O.	8760	0.02 lb/MMBtu 0.03 lb/MMBtu			85.7	375.4	Rule 62.204.800(7)(b)2, F.A.C.	A.5, A.6 A.7
Visible Emissions	Coal F.O.	8760	20% Opacity					Rule 62.204.800(7)(b)2, F.A.C.	A.8
Sulfur Dioxide	Coal F.O.	8760	0.25 lb/MMBtu 0.80 lb/MMBtu			3643	4693	Rule 62.204.800(7)(b)2, F.A.C. Rule 62.204.800(7)(b)2, F.A.C.	A.10,Sec IV-A2 A.11
Nitrogen Oxide	Coal F.O.	8760	0.17 lb/MMBtu 0.30 lb/MMBtu			729	3191	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.15,Sec IV-A2 A.15
Carbon Monoxide	Coal	8760	0.15 lb/MMBtu			643	2816	PSD-FL-084	A.18
VOC	Coal	8760	0.015 lb/MMBtu			64	282	PSD-FL-084	A.19
Sulfuric Acid Mist	Coal	8760	0.033 lb/MMBtu			140	613	PPS PA 81-14/SA1	A.20
Beryllium	Coal	8760	5.2×10^{-6} lb/MMBtu			0.022	0.1	PPS PA 81-14/SA1	A.21
Mercury	Coal	8760	1.1×10^{-5} lb/MMBtu			0.046	0.2	PPS PA 81-14/SA1	A.22
Lead	Coal	8760	1.5×10^{-4} lb/MMBtu			0.64	2.8	PPS PA 81-14/SA1	A.23
Fluorides	Coal	8760	4.2×10^{-4} lb/MMBtu			1.8	7.9	PPS PA 81-14/SA1	A.24

*Unit No.1 shall fire "new oil". Unit No.2 shall fire "new oil" as well as on-specification used fuel oil as per specific condition D.22.

** The "Equivalent Emissions" listed are for informational purposes only. Unit 1 NO_X emission limit is 0.60 lb/MMBtu on a 30-day rolling average, and 0.46 lb/MMBtu on an annual average.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Table 1-2, Summary of Air Pollutant Standards and Terms

Orlando Utilities Commission
Stanton Energy Center

Permit No.: 0950137-005-AV
Facility ID No.: 0950137

E.U. ID Nos. Brief Description

-003	Auxiliary Boiler #3								
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	F.O.	150	0.015 lb/MMBtu			1.2	0.1	Rules 62-4.160(2), F.A.C.	B.4
Visible Emissions	F.O.	150	20% Opacity					Rule 62-4.160(2), F.A.C.	B.4
Sulfur Dioxide	F.O.	150	0.51 lb/MMBtu			42.3	3.2	Rule 62-4.160(2), F.A.C.	B.4
Nitrogen Oxide	F.O.	150	0.16 lb/MMBtu			13.3	0.1	Rule 62-4.160(2), F.A.C.	B.4

-004, -005, -006, and -007	Fly Ash Silo System								
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
Visible Emissions	N/A	8760	5% Opacity					PPS PA 81-14/SA1	C.2

-025 and -026	Combined-Cycle Combustion Turbines								
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
Nitrogen Oxides	Natural gas		3.5 ppmvd					0950137-002-AC	**E.14.**
	Fuel oil	1000	10 ppmvd					0950137-002-AC	**E.14.**
Carbon Monoxide	Natural gas		17 ppmvd					0950137-002-AC	**E.15.**
	Fuel oil	1000	14 ppmvd					0950137-002-AC	**E.15.**
Volatile organic compounds	Natural gas		6.3 ppmvd					0950137-002-AC	**E.16.**
	Fuel oil	1000	2.7 ppmvd					0950137-002-AC	**E.16.**
Sulfur dioxide	Natural gas		1.5 grains per 100 standard cubic foot				134	0950137-002-AC	**E.17.**
	Fuel oil	1000	.05% sulfur by weight					0950137-002-AC	**E.17.**
Visible Emissions	N/A	8760	10% Opacity					0950137-002-AC	**E.18.**

* The auxiliary boiler is fired primarily with No. 2 "new oil" having a sulfur content less than 0.5 percent, by weight.
** The "Equivalent Emissions" listed are for informational purposes only.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Table 2-1, Summary of Compliance Requirements

Orlando Utilities Commission
Stanton Energy Center

Permit No. 0950137-005-AV
Facility ID No. 0950137

E.U. # -001	Fossil Fuel Fired Steam Generator #1						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
PM Emissions	Coal	EPA Method 5B	Annual	N/A	6 hours	No	A.41(2)
Visible Emissions	Coal	EPA Method 9	Annual	N/A	1 hour	Yes	A.41(3)
Sulfur Dioxide	Coal	EPA method 6	Annual	N/A	1 hour	Yes	A.37(1)
Nitrogen Oxide	Coal	EPA Method 7	Annual	N/A	1 hour	Yes	A.37(2)

E.U. # -002	Fossil Fuel Fired Steam Generator #2						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
PM Emissions	Coal	EPA Method 5B	Annual	N/A	6 hours	No	A.41(2)
Visible Emissions	Coal	EPA Method 9	Annual	N/A	1 hour	Yes	A.41(3)
Sulfur Dioxide	Coal	EPA Method 6	Annual	N/A	1 hour	Yes	A.37(1)
Nitrogen Oxide	Coal	EPA Method 7	Annual	N/A	1 hour	Yes	A.37(2)
Carbon Monoxide	Coal	EPA Method 10	Annual	N/A	N/A	No	A.44(1)
VOC	Coal	EPA Method 18	Annual	N/A	N/A	No	A.44(2)
Beryllium	Coal	EPA Method 104	Annual	N/A	N/A	No	A.44(3)
Mercury	Coal	EPA Method 101A	Annual	N/A	N/A	No	A.44(4)
Lead	Coal	EPA Method 12	Annual	N/A	N/A	No	A.44(5)
Fluorides	Coal	EPA Method 13A	Annual	N/A	N/A	No	A.44(6)

Table 2-2, Summary of Compliance Requirements

Orlando Utilities Commission
Stanton Energy Center

Permit No.: 0950137-005-AV
Facility ID No.: 0950137

E.U. # -003	Auxiliary Boiler #3						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Visible Emissions	F.O.	EPA Method 9	Annual	N/A	1 hour	No	B.5

E.U. # -004,-005,-006 and -007			Fly Ash Silo System				
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Visible Emissions	N/A	EPA Method 9	Annual	N/A	1 hour	No	C.2

-025 and -026			Combined-Cycle Combustion Turbines				
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Nitrogen Oxides	Natural gas	EPA Method 7E	Annual			Yes	**E.23.**
	Fuel oil					Yes	**E.23.**
Carbon Monoxide	Natural gas	EPA Method 10	Annual			Yes	**E.23.**
	Fuel oil					Yes	**E.23.**
Volatile organic compounds	Natural gas	EPA Methods 18, 25,and/ or 25A	Initial				**E.23.**
	Fuel oil		Initial				**E.23.**
Sulfur dioxide	Natural gas	Fuel analysis					**E.25.**
	Fuel oil						**E.25.**
Visible Emissions	N/A	EPA Method 9	Annual				**E.23.**

1 - Frequency base date established for planning purposes only; see guidance memo and Rule 62-297.310, F.A.C.
2 - Continuous Monitoring System.
3 - EPA Method 17 may be used only if the stack gas exit temperature is less than 375 degrees F.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.