Gulf Power Company

Crist Electric Generating Plant

Facility ID No. 0330045
Escambia County

Title V Air Operation Permit Revision

Permit No. 0330045-047-AV

(Revision of Title V Air Operation Permit Nos. 0330045-038-AV and 0330045-042-AV)

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance

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

Telephone: (850) 717-9000
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Compliance Authority:

Department of Environmental Protection
Northwest District Office

160 Governmental Center, Suite 308
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Title V Air Operation Permit Revision

Permit No. 0330045-047-AV

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Florida Department of Environmental Protection

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2600 Blair Stone Road
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Rick Scott
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PERMITTEE:
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One Energy Place
Pensacola, Florida 32520-0328

Permit No. 0330045-047-AV
Crist Electric Generating Plant
Facility ID No. 0330045
Title V Air Operation Permit Revision

The purpose of this permitting project is to revise the existing Title V air operation permit Nos. 0330045-038-AV and 0330045-042-AV for the above referenced facility. The existing Crist Electric Generating Station, which is located in Escambia County on Pate Road, off of 10 Mile Road on Governors Bayou, Pensacola, Florida 32514. UTM Coordinates are: Zone 16; 478.5 Kilometer (km) East, 3381.44 km North. Latitude is: 30° 34' 0.6552" North; and, Longitude is: 87° 13' 35.1261" West.

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

0330045-038-AV Effective Date; April 10, 2015
0330045-042-AV Effective Date July 6, 2016
0330045-047-AV Effective Date: November 20, 2017
Renewal Application Due Date: August 29, 2019
Expiration Date: April 10, 2020

Executed in Tallahassee, Florida

David Lyle Read, P.E.
2017.11.17 13:14:49 -05'00'

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

SA/dlr/sh

Subsection A. Facility Description.

The existing facility consists of four predominantly coal-fired fossil fuel steam generators (boilers) and two fly ash silos. Boilers 4 and 5 were Acid Rain Phase I substitution Units. Boilers 6 and 7 were Acid Rain Phase I Units. All four boilers are subject to the Acid Rain Phase II. In addition, all the boilers are subject to 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants Coal-and Oil-Fired Electric Utility Steam Generating Units which is also referred to as the Mercury and Air Toxics Standards (MATS). Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Natural gas, fuel oil and on-specification used oil are used as supplemental fuels in all four of the boilers. The facility also has engines which are regulated under 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) and 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines adopted in Rules 62-204.800(11)(b) & 8(b), F.A.C., respectively.

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
Regulated Emissions Units	
004	Boiler Number 4 - 1,096.7 MMBtu/hour (Substitution Acid Rain Phase I)
005	Boiler Number 5 - 1,096.7 MMBtu/hour (Substitution for Acid Rain Phase I)
006	Boiler Number 6 - 3,704.8 MMBtu/hour (Acid Rain)
007	Boiler Number 7 - 6,406.4 MMBtu/hour (Acid Rain)
008	Fly Ash Silos (3)
014	Unit 007, Mechanical Draft Cooling Tower with a maximum circulation rate of 190,000 GPM
015	Limestone Handling Equipment, Including 2 Silos
017	General Purpose Emergency RICE Units, Subject to 40 CFR 60, Subpart IIII
018	General Purpose Emergency RICE Units, Subject to 40 CFR 63, Subpart ZZZZ
Unregulated Emissions Units and Activities (See Appendix U)	
009	Material Handling of Coal and Ash
010	Fugitive PM Sources - On-site Vehicles
012	Cooling Towers (2), one shared by Units 004 and 005 and other for Unit 006
013	Fugitive PM Sources - Sandblasting Operations
016	Gypsum Handling Equipment

Also included in this permit are miscellaneous insignificant emissions units and/or activities (see Appendix I, List of Insignificant Emissions Units and/or Activities).

Subsection C. Applicable Regulations.

Based on the Title V air operation permit revision application received February 3, 2016, this facility is a major source of hazardous air pollutants (HAP). The existing facility is a Prevention of Significant Deterioration (PSD) major source of air pollutants in accordance with Rule 62-212.400, F.A.C. A summary of applicable regulations are shown in the following table.

Applicable Regulations	EU No(s).
Federal Rule Citations	
40 CFR 60, Subpart A, NSPS General Provisions	017
40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	
40 CFR 63, Subpart A, NESHAP General Provisions	018
40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	
40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants Coal-and Oil-Fired Electric Utility Steam Generating Units	004, 005, 006, 007
40 CFR 75 Acid Rain Monitoring Provisions	
State Rule Citations	
Rule 62-204, F.A.C. (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference)	004, 005, 006, 007, 008
Rule 62-210, F.A.C. (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms)	004, 005, 006, 007, 008, 014, 015
Rule 62-213, F.A.C. (Title V Air Operation Permits for Major Sources of Air Pollution)	
Rule 62-214, F.A.C. (Requirements For Sources Subject To The Federal Acid Rain Program) Federal Acid Rain Program, Phase II	004, 005, 006, 007
Rule 62-296, F.A.C. (Emission Limiting Standards)	004, 005, 006, 007, 008, 015
Rule 62-297, F.A.C. (Stationary Sources - Emissions Monitoring)	004, 005, 006, 007, 008, 015

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

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

Emissions and Controls

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

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department. Nothing is deemed necessary and ordered at this time. [Rule 62-296.320(1), F.A.C.]

FW4. General Visible Emissions. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b), F.A.C.]

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

a. Ash and gypsum leaving the facility will be hauled in closed container trucks or barges. Ash and gypsum being disposed of on plant property will be mixed with water as needed as it is being loaded into the trucks for transport to the landfill.
b. The plant ash and gypsum haul roads will be watered as necessary to control any unconfined particulate matter.
c. Grassing over each section of the ash and gypsum landfill as it reaches its capacity to prevent any particulate matter being lift into the wind.
d. Regular packing of the coal pile to reduce blowing dust and aid in the prevention of coal fires.
e. Application of a dust suppressant to the coal, limestone and gypsum on the conveyor belts as necessary.
f. Biomass Fugitive Dust Emissions: The permittee shall minimize unconfined particulate matter emissions from the storage and handling of carbonaceous fuels by using dust suppressing techniques such as covering, confining, or applying water to the affected areas, as necessary.

[Rule 62-296.320(4)(c), F.A.C. and Permit No. 0330045-023-AC]

Annual Reports and Fees

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

FW6. Electronic Annual Operating Report and Title V Annual Emissions Fees. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1st of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by

submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. Each Title V source must pay between January 15 and April 1 of each year an annual emissions fee in an amount determined as set forth in subsection 62-213.205(1), F.A.C. The annual fee shall only apply to those regulated pollutants, except carbon monoxide and greenhouse gases, for which an allowable numeric emission-limiting standard is specified in the source's most recent construction permit or operation permit. Upon completing the required EAOR entries, the EAOR Title V Fee Invoice can be printed by the source showing which of the reported emissions are subject to the fee and the total Title V Annual Emissions Fee that is due. The submission of the annual Title V emissions fee payment is also due (postmarked) by April 1st of each year. A copy of the system-generated EAOR Title V Annual Emissions Fee Invoice and the indicated total fee shall be submitted to: **Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070.** Additional information is available by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rules 62-210.370(3), 62-210.900 & 62-213.205, F.A.C.; and, §403.0872(11), Florida Statutes (2013)]

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

{Permitting Note: The Title V Annual Emissions Fee form (DEP Form No. 62-213.900(1)) has been repealed. ***A separate Annual Emissions Fee form is no longer required to be submitted by March 1st each year.****}*

FW7. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit and to the US. EPA at the address shown below within 60 days after the end of each calendar year during which the Title V air operation permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

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

FW8. Prevention of Accidental Releases (Section 112(r) of CAA).

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. (See paragraph e., below.)

b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Division of Emergency Management, as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.

c. The owner or operator shall submit the required annual registration fee to the Division of Emergency Management on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 27P-21, F.A.C.

d. Any required written reports, notifications, certifications, and data required to be sent to the Division of Emergency Management, should be sent to: Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9970, Fax: (850) 488-1739.

e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent electronically through EPA's Central Data Exchange system at the following address: https://cdx.epa.gov. Information on electronically submitting risk management plans using the

Central Data Exchange system is available at: http://www2.epa.gov/rmp. The RMP Reporting Center can be contacted at: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.

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

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

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

FW9. In lieu of Condition TV15. of Appendix TV, Title V General Conditions, the following condition applies:

Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program. [Rule 62-213.460, F.A.C.]

In addition, this permit shield does not currently encompass major or minor source construction permit requirements that are deemed applicable to the source by a court of competent jurisdiction. The source shall not be shielded from any such requirements found, after the exhaustion of appeals, to be applicable by such court, and in the event that such a finding is made and the appeals wherefrom are exhausted, this will provide a basis for reopening the permit to establish a schedule for complying with these requirements. Until such time as a final decision is reached after the exhaustion of appeals, no compliance schedule shall be necessary or required. Furthermore, the annual compliance certification shall not be required to address such matters until a final decision is reached. It is specifically recognized that this exception to the permit shield applies to a determination by such court, after exhaustion of appeals, that major or minor new source construction permit requirements apply to the source. Nothing in the permit has made any specific finding of non-applicability of any PSD, NSPS, or SIP minor source review requirements for any modifications to which these requirements should have applied.

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

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Subsection A. Emissions Units 004, 005, 006, 007 and 015

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

EU No.	Brief Description
004	Boiler Number 4 - 1,096.7 MMBtu/hour (Substitution Phase I Acid Rain Unit)
005	Boiler Number 5 - 1,096.7 MMBtu/hour (Substitution Phase I Acid Rain Unit)
006	Boiler Number 6 - 3,704.8 MMBtu/hour (Phase I Acid Rain Unit)
007	Boiler Number 7 - 6,406.4 MMBtu/hour (Phase I Acid Rain Unit)
015	Limestone Handling Equipment, Including 2 Silos

Emissions unit number 004 is a tangentially fired, dry bottom boiler designated as "Boiler Number 4" manufactured by Combustion Engineering. It is rated at a maximum heat input of 1,096.7 MMBtu/hour when firing pulverized coal, natural gas, No. 2 fuel oil, or on-specification used oil. Emissions unit number 005 is a tangentially fired, dry bottom boiler designated as "Boiler Number 5" manufactured by Combustion Engineering. It is rated at a maximum heat input of 1,096.7 MMBtu/hour when firing pulverized coal, natural gas, No. 2 fuel oil, or on-specification used oil. Units 004 and 005 can burn Biomass up to 40.2 MMBtu/hour. Units 004 and 005 were Phase I substitution units and are Phase II Acid Rain units. Gulf Power operates a temporary mercury research center using a slipstream of flue gas from unit 005 (Permit No. 0330045-011-AC) for evaluating mercury (Hg) emission reduction techniques.

Emissions unit number 006 is a front wall fired, dry bottom boiler designated as "Boiler Number 6" manufactured by Foster Wheeler. It is rated at a maximum heat input of 3,704.8 MMBtu/hour when firing pulverized coal or natural gas, and 714.8 MMBtu/hr when firing No. 2 fuel oil or on-specification used oil. Emissions unit number 007 is a front and rear wall fired, dry bottom boiler designated as "Boiler Number 7" manufactured by Foster Wheeler. It is rated at a maximum heat input of 6,406.4 MMBtu/hour when firing pulverized coal or natural gas, and 1,282 MMBtu/hour when firing No. 2 fuel oil or on-specification used oil. Fuel oil is used as a back-up fuel in both units and for periods of start-up and flame stabilization.

These emissions units are regulated under Acid Rain, Phase II and they are subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV). These emissions units pre-date Prevention of Significant Deterioration (PSD) regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input.

Emissions unit number 015 is a limestone handling system for the receipt, storage, and sluicing of limestone. The system consists of a powdered limestone unloading station, two closed silos, two limestone slurry mix tanks, and associated pumps, valves, instrumentation and piping. The permittee shall maintain and operate a baghouse on each silo designed to meet a particulate matter emissions specification of 0.01 grains per actual standard cubic feet. When needed, replacement bags shall be selected that meet this equipment specification. The baghouse vents are located at the top of the limestone storage silos. The limestone handling system shall be maintained and operated to minimize emissions of fugitive particulate matter by confining, enclosing or wetting (as necessary). [Permit No. 0330045-023-AC, Rule 62-4.070, F.A.C.]

{Permitting Notes: PM emissions from emissions units 004 and 005 are controlled by hot side electrostatic precipitators (ESP) manufactured by Buell, updated with GE ENERGY ESP-3 plates with RDE-1 rigid discharge electrodes, and cold side ESP manufactured by Buell, Model 1.1x48k33-1p. Nitrogen Oxides (NO_X) emissions from units 004 and 005 are controlled by low-NO_X burner tips and selective non-catalytic reduction (SNCR). The SNCR system is designed for a target NO_X reduction of 25% as measured across the SNCR unit inlet and outlet. The designed target ammonia slip level is 5 parts per million per volume (ppmv) corrected to 3% oxygen (O_2) based on a 24-hour average. Unit 004 began commercial operation on July 1, 1959. Unit 005 began commercial operation on June 1, 1961. The generator nameplate rating for unit 004 is 93 MW. The generator nameplate rating for unit 005 is 93 MW. PM emissions from unit 006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). PM emissions from unit 007 are controlled by cold side electrostatic

precipitators designed by Alstom Power Inc. NO_X emissions from units 006 and 007 are controlled by Foster Wheeler Low NO_X Burners and by a Selective Catalytic Reduction (SCR) system designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. Unit 006 began commercial operation on May 1, 1970. Unit 007 began commercial operation on August 1, 1973. The permittee operates a wet Flue Gas Desulfurization (FGD) system to control SO_2 emissions from Units 4 - 7. Units 4 - 7 share a common stack under normal conditions with the wet FGD system in operation. Sulfuric Acid Mist emissions are controlled by hydrated lime injection on the common duct to all four units just prior to the inlet of the FGD system. Boiler additives are injected in Units 4 - 7 to reduce slag in the boilers. Common stack height = 490 feet, exit diameter = 35 feet, exit temperature = 131° F; actual volumetric flow rate = 3,282,000 acfm. The two existing stacks for Units 4, 5 and Units 6, 7 will remain as bypass stacks for: periods of startup and shutdown of Units 4 - 7; malfunction of Units 4 - 7 (any or all) or the wet FGD system; or, repair or scheduled maintenance of the wet FGD system. Under normal operating conditions, the existing stack for Units 4/5 will be used to provide makeup air to the system. Units 004 and 005 common bypass stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 ºF, actual volumetric flow rate = 596,012 actual cubic feet per minute (acfm). Units 006 and 007 common bypass stack height = 450 feet, exit diameter = 23.2 feet, exit temperature = 320 ºF, actual volumetric flow rate = 2,975,540 acfm. }

{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). The four boilers are also subject to 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants Coal- and Oil-Fired Electric Utility Steam Generating Units.}

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

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

EU No.	MMBtu/hr Heat Input	Fuel Type
004	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil
	40.2	Biomass
005	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil
	40.2	Biomass
006	3,704.8	Coal
	3,704.8	Natural Gas
	714.8	No. 2 Fuel Oil (for start-up and as needed for flame stabilization)
	714.8	On-Specification Used Oil
007	6,406.4	Coal
	6,406.4	Natural Gas
	1,282	No. 2 Fuel Oil (for start-up and as needed for flame stabilization)
	1,282	On-Specification Used Oil
015	N/A	Limestone Handling Equipment, Including 2 Silos

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330, and 62-296.405, F.A.C., Permit Nos. AC17-2126, AC17-2127, 0330045-010-AC and 0330045-013-AC]

A.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(3), F.A.C.]

A.3. Methods of Operation.

a. *Fuels.* The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil, and/or on-specification used oil (see **Specific Condition A.50.**). For Units 006 and 007 the No. 2 Fuel oil is only used for periods of start-up and as needed for flame stabilization. Units 004 and 005 may also fire carbonaceous fuel (Biomass). In addition, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. *Other.*

(1) Supplemental injection of ammonia at a rate of 25 to 40 pounds per hour for Units 006 and 007.

c. *Biomass Fuels*. Subject to the conditions of this permit, only units 004 and 005 may also fire carbonaceous fuel consisting of the following untreated materials: wood chips, switch grass, sawdust, and sander dust in addition to the authorized fuels listed above. These materials shall be substantially free of plastics, metals, paint or other chemicals. Heat input rate from biomass fuels shall not exceed 40.2 MMBtu per hour for each unit. The maximum hourly firing rates of carbonaceous fuels for each unit are: 4.7 tons of wood chips per hour, 2.9 tons of switch grass per hour, 3.7 tons of sawdust per hour, and 3.7 tons of sander dust per hour. The above limits are not cumulative and only one carbonaceous fuel type may be fired at a time.

[Rule 62-213.410, F.A.C.; and, Permit Nos. 0330045-011-AC, 0330045-013-AC and 0330045-029-AC, Specific Conditions C.1. & C2.; 0330045-041-AC]

A.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels. [Rules 62-213.440, 62-210.200(PTE), F.A.C.]

Control Technology

A.5. Selective Non-Catalytic Reduction (SNCR) System. Fuel Tech, Inc., designed the SNCR systems for Units 4 and 5 to be used on an "as needed" basis to meet the plant-wide NO_X limit in **Specific Condition A.16**. Urea is delivered by truck (or possibly rail) and stored on site as a 40% aqueous solution in one 45,000 gallon tank. When operated at peak load, this provides approximately 7 days of operating inventory. The solution will be maintained at a temperature of approximately 40° F by circulating through the SNCR system piping loop heating module. Using plant service water or other dilution water source, the metering module dilutes the reagent to a predetermined concentration (approximately 30%) and precisely controls the flow of the diluted reagent to distribution modules located near the boiler injection point. The distribution modules provide the final control of diluted reagent and atomizing/cooling (plant) air being delivered to each injector. The diluted reagent is injected into the boiler via wall-mounted air atomizing lances, which will be installed across the face of the boiler at an elevation of 159'-0" for each unit. At peak load for Unit 004, with 0.36 lb/MMBtu inlet NO_X and 25% reduction, urea injection would be 233 lb/hr on a dry basis. This translates to an ammonia flow of 132 lb/hr. At peak load for Unit 005, with 0.36 lb/MMBtu inlet NO_X and 25% reduction, urea injection would be 238 lb/hr on a dry basis. This translates to an ammonia flow of 135 lb/hr. The SNCR is designed with a maximum ammonia slip concentration of 5 ppmvd corrected to 3% O_2 (24 hour basis) in the duct cross-sectional area for all boiler loads. There are no provisions for continuously monitoring ammonia concentration in the flue gas. When ammonia measurements in the flue gas are required, EPA Method CTM-027 or other methods approved by EPA such as Method 320, which incorporates Fourier transform Infrared Spectroscopy (FTIR) will be used. [Permit No. 0330045-013-AC]

A.6. Selective Catalytic Reduction (SCR) Systems. The SCR systems were designed to achieve no less than an 85% reduction from the baseline emissions rate of 0.70 lb/MMBtu in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. The storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68. Southern Company Services Inc. designed the SCR systems for Units 006 & 007, which generally consist~~s~~ of the following:

a. *Catalyst Structure/Design Specifications.*

(1) Unit 6. The catalyst consists of titanium dioxide and molybdenum oxide with vanadium pentoxide as the active component. The catalyst is fabricated by applying ceramic catalyst material to a perforated stainless steel mesh grid plate. The catalyst structure is a honey-comb type. The operational temperature range is approximately 600° to 800° F. The initial configuration is for a catalyst volume of approximately 460 cubic meters (16,260 cubic feet) divided between three catalyst layers. The design inlet NO_X concentration is 0.5 lb/MMBtu and the design output NO_X emissions is 0.07 lb/MMBtu.

(2) (Unit 7. Arranged in four layers, the catalyst is a plate-type structure fabricated by applying ceramic catalyst material to a perforated stainless steel mesh grid plate. The active catalyst component is vanadium pentoxide. The system has an operational temperature range between approximately 600° to 800° F (optimum temperature > 680° F). The initial configuration had a catalyst volume of approximately 26,000 cubic feet in 2½ layers. As the catalyst gradually deactivates through use, the remaining layers will be filled and old layers replaced. With all four potential layers in place, the catalyst volume is approximately 41,600 cubic feet.

b. *Ammonia Storage, Mixing and Injection Systems.* Anhydrous ammonia is delivered by truck or rail and stored on site in three 20,500 gallons tanks.

(1) Unit 6. Ammonia is diluted with air (< 10% by volume) and injected into the SCR inlet duct through the ammonia injection grid (AIG), which is divided into about two dozen zones. Each zone is equipped with a flow indicator and manual control valve for tuning the AIG to match the inlet NO_X profile. Effective ammonia distribution and NO_X conversion are dependent on the velocity profile entering the AIG. A static mixer installed upstream of the AIG creates flow resistance, flattens the velocity profile, and provides uniform gas flow. Downstream of the AIG, a second static mixer is positioned at the AIG injection points to impart a swirl to the diluted ammonia and promote good mixing with the flue gas. For 85% NO_X conversion, the design molar ratio of ammonia-to-NO_X is 0.95 at SCR inlet.

(2) (Unit 7. Ammonia is distributed into the SCR inlet duct through the ammonia injection grid (AIG), which is divided into about two dozen zones. Each zone is equipped with a flow indicator and manual control valve for tuning the AIG to match the inlet NO_X profile. A static mixer installed upstream of the AIG creates flow resistance, flattens this profile, and makes gas flow uniform. A second static mixer is installed downstream of the AIG. The elements of this mixer are precisely oriented with the AIG injection points to impart a swirl to the diluted ammonia and promote good mixing with the flue gas. A manual gas sampling grid (GSG) is installed downstream of the last catalyst layer, which allows a high-resolution traverse of the flue gas stream. Gas composition data collected from the GSG is used to precisely adjust and tune the AIG. The preliminary design was based on a 0.95 molar ratio of ammonia-to-NO_X.

c. *Ammonia Control Systems.* The ammonia control systems for Units 6 and 7 consist of a control loop with a cascaded, feed-forward control scheme. Process monitors will provide NO_X emission rate data collected at the inlet to and the outlet from each of the SCR systems. The ammonia injection rate is set based on a variety of input data including the measured NO_X rates at the SCR inlet/outlet, the outlet NO_X set point, the heat input to the boiler, the actual NO_X rate measured by the FGAS monitor, and a scaling factor based on the molecular weights of ammonia and NO_X. The systems are capable

of continually adjusting flow control valves to fine-tune the ammonia injection rate based on changing gas stream conditions.

d. *SCR Bypass.* The Unit 6 and Unit 7 SCR designs incorporate dampers and ductwork to provide the capability of bypassing the SCR systems. The bypass is most commonly used to gradually heat or cool the catalyst structure to minimize thermal fatigue during startup and shutdown. During catalyst maintenance and repair, it would also allow access to the SCR reactors without requiring complete shutdown of the Unit 6 or Unit 7 boiler.

e. *Unit 6 Ammonia Slip.* There are no provisions for continuously monitoring ammonia concentration in the flue gas. When ammonia measurements in the flue gas are required, a wet chemical method will be utilized. These measurements are taken periodically over the operating life of the SCR catalyst. More frequent tracking of ammonia slip will be monitored by measuring the amount of residual ammonia adsorbed by the fly ash. Fly ash samples will be measured periodically using an ion-specific electrode. Ammonia slip may also be estimated from the ammonia injection monitoring system based on the NO_X rate at the SCR inlet/outlet and the ammonia injection rate.

f. *Unit 6 Gas Sampling Grid (GSG).* During commissioning and periodically over the life of the system, it will be necessary to tune the AIG to optimize the distribution of ammonia in the SCR inlet duct relative to the NO_X distribution to provide optimum NO_X conversion with minimum ammonia slip. To facilitate tuning, a manual gas sampling grid (GSG) is installed downstream of the last catalyst layer. The GSG allows a high-resolution traverse of the flue gas stream for composition across the outlet of the SCR, which can be used to precisely adjust the AIG. The GSG is comprised of individual small-bore (~½") heavy-wall pipes extending from outside the SCR to distributed sampling locations below the last catalyst layer. Portable equipment is used to sample and measure gas concentrations using the GSG.

[Permit Nos. 0330045-005-AC, Specific Condition 3 and 0330045-028-AC, Specific Condition 3]

A.7. Operation of NO_X Control Devices.

a. *SNCR Systems for Units 004 and 005.* The permittee shall maintain and operate SNCR systems for Units 004 and 005 to reduce emissions of nitrogen oxides (NO_X), as needed, in order to comply with the plant-wide nitrogen oxides (NO_X) Limit in **Specific Condition A.16**. The SNCR systems for Units 004 and 005 were designed to achieve no less than a 25% reduction in NO_X emissions as measured across the SNCR unit inlet and outlet. Both systems shall be maintained to operate as designed. The designed target ammonia slip level is 5 ppmv corrected to 3% O_2 based on a 24-hour average. The storage of urea shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

b. *SCR System for Units 006 and 007.* The permittee shall operate and maintain an SCR system for Units 006 and 007 to reduce emissions of nitrogen oxides (NO_X). The SCR systems were designed to achieve no less than an 85% reduction from the baseline emissions rate of 0.70 lb/MMBtu in NO_X emissions as measured across the SCR unit inlet and outlet. The SCR systems shall be maintained to operate as designed. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. The storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Permit Nos. 0330045-005-AC, 0330045-013-AC and 0330045-028-AC]

A.8. SCR Bypass, Startup/Shutdown. During Units 006 and 007 startup and shutdown, the SCR system may be bypassed in accordance with manufacturer's recommended procedures to allow for controlled catalyst heating and cooling. During startup, the SCR system shall be on line and functioning when the minimum operating temperature of the catalyst is achieved (approximately 600° F). During shutdown, the SCR system may be removed from service when the catalyst temperature drops below 600° F. [Rule 62-210.700, F.A.C. and Permit Nos. 0330045-005-AC and 0330045-028-AC]

A.9. SCR Bypass, Catalyst Maintenance and Repair. The permittee may bypass the SCR systems to perform maintenance and repair for up to 360 hours per consecutive 12 months during non-ozone events, for each unit. The daily NO_X emissions rates for these periods shall be included when demonstrating compliance with the plant-wide 30-day NO_X standard. The permittee shall notify the Compliance Authority in advance of the purpose of the SCR bypass, the expected dates of SCR bypass, and the expected duration of SCR bypass. To the extent practical, the permittee shall schedule regular maintenance of the SCR system for the non-ozone season. [Rules 62-210.700, 62-4.070(3), F.A.C., Permit Nos. 0330045-005-AC, 0330045-017-AC and 0330045-036-AC]

{Permitting Note: The ozone season is defined as May 1st through September 15th. An Ozone event is defined as any level on the Air Quality Index for zone greater than good or moderate (green or yellow).}

A.10. Operation of Sulfur Dioxide (SO_2) Control Devices. The permittee shall operate a wet flue gas desulfurization (FGD) system to control SO_2 emissions from Units 4 - 7. The system consists of a large scrubber vessel as well as a number of subsystems for transport and processing flue gas exhaust, limestone, gypsum, other solids, and water. All four boiler exhausts are directed to the single scrubber reactor where a limestone slurry is injected to chemically react with SO_2 in the scrubber vessel for removal as gypsum. The wet FGD system shall be tuned, operated, and maintained as described in the application, approved drawings, plans, and other documents on file with the Department. A FGD Scrubber operational day shall be defined as a calendar day during which one or more of the boilers operated and the FGD scrubber was operational or only being bypassed for purposes of short-term maintenance as described below.

a. For normal operations, SO_2 emissions shall be determined by CEMS emissions data. The SO_2 mass emissions rates shall be calculated in terms of "pounds per day" for each calendar day of operation by summing the hourly mass emissions rates (lb/hour) determined from the actual heat input rates (MMBtu/hour) and the monitored emissions levels (lb/MMBtu). The actual heat input rates will be determined by fuel firing rates and heating values.

b. For FGD scrubber bypass operation, SO_2 emissions shall be monitored and determined in accordance with the "Crist Alternative Monitoring Plan" (File No. 07-D-AP) and Appendix MATS. The permittee is authorized to bypass the FGD scrubber in accordance with the following conditions.

(1) *Startup and Shutdown*. The permittee is authorized to bypass the FGD scrubber during the startup and shutdown of each emissions unit. The permittee may exclude SO_2 emissions collected during startup and shutdown from the 30-day rolling compliance total. Although not limited, such periods of bypass are estimated to be less than 96 hours per year per unit. In addition, during startup, the permittee shall use clean fuels (natural gas and/or No. 2 fuel oil) for ignition, and shall use clean fuels to the maximum extent possible throughout the startup period. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels and must be used to the maximum extent possible, in accordance with 40 CFR 63, Subpart UUUUU (See **Specific Condition A.52**)

(2) *Short-Term Maintenance*. The permittee is authorized to bypass the FGD scrubber to conduct short-term maintenance to correct problems with limestone-gypsum management and operational problems with the FGD system. During such periods, the permittee shall include representative SO_2 emissions rates in the 30-day rolling compliance total. Such short-term maintenance periods are not considered part of long-term maintenance (annual routine maintenance, periodic pre-planned maintenance or repair for force majeure scrubber outages).

(3) *Long-Term Maintenance*. The permittee is authorized to bypass the FGD scrubber to conduct annual routine maintenance of the FGD scrubber system. For such periods, the permittee may exclude up to 360 hours per calendar year from the 30-day rolling compliance total. The permittee is authorized to bypass the FGD scrubber to conduct periodic pre-planned scrubber maintenance (based on best practices) and scrubber repairs due to force majeure outages. For

such periods, the permittee may exclude up to an additional 360 hours per calendar year from the 30-day rolling compliance total. In addition, the permittee shall burn clean fuels to the maximum extent possible during long-term maintenance bypass operations, and shall convert to firing clean fuels as soon as practicable during force majeure outages.

The permittee shall use the protocol in 40 CFR 75 to calculate the initial representative SO_2 emissions for bypass operations. If this initial conservative estimate indicates a compliance issue, the permittee may recalculate and determine compliance using the representative SO_2 emissions based on the actual fuel sulfur content and fuel firing rate. During a FGD scrubber bypass, each unit shall remain in compliance with all other valid SO_2 emissions standards. [40 CFR 63, Subpart UUUUU; Rule 62-4.080(1), F.A.C; and Permit Nos. 0330045-023-AC and 0330045-041-AC]

A.11. Operation of FGD Subsystems. The subsystems used to support the FGD system consist of the following:

a. *Flue Gas Handling*. The FGD exhausts to a common stack for Units 4 – 7, which is the point of emissions under normal conditions while the wet FGD system is in operation. The two existing stacks for Units 4, 5 and Units 6, 7 remain as bypass stacks for: periods of startup and shutdown of Units 4 - 7; malfunction of Units 4 - 7 (any or all) or the wet FGD system; or, repair or scheduled maintenance of the wet FGD system. Under normal operating conditions, the existing stack for Units 4/5 will be used to provide makeup air to the system.

b. *Limestone Handling*. A limestone handling system is operated for the receipt, storage, and sluicing of limestone. The system consists of a powdered limestone unloading station, two closed silos, two limestone slurry mix tanks, and associated pumps, valves, instrumentation and piping. The permittee shall maintain and operate a baghouse on each silo designed to meet a particulate matter emissions specification of 0.01 grains per actual standard cubic feet. New and replacement bags shall be selected that meet this equipment specification. The limestone handling system shall be maintained and operated to minimize emissions of fugitive particulate matter by confining, enclosing or wetting (as necessary).

c. *Gypsum Handling*. A gypsum handling system is operated to transport, store, dewater, and load for shipment the gypsum produced in the scrubber vessel. The equipment includes tanks, pumps, piping, valves, instrumentation, hydrocyclones, vacuum filters, and conveyors. There are two vacuum filters with accessories to serve units 4 - 7. To the extent practicable, conveyors transporting dewatered gypsum must be enclosed. The remainder of the gypsum handling system shall be maintained and operated to minimize emissions of fugitive particulate matter by confining, enclosing or wetting (as necessary).

[0330045-015-AC and 0330045-023-AC]

{Permitting Note: The wet FGD system is based on the Model CT-121 wet FGD process licensed by Southern Company from Chiyoda Corporation. The preliminary design is for removal of approximately 95% of the SO_2 emissions. In addition, the wet FGD system is expected to: remove an estimated 50% to 70% of the particulate matter emissions; remove an estimated 95% of the hydrogen chloride and hydrogen fluoride emissions; and capture an estimated 80% of the oxidized mercury.}

A.12. Hydrated Lime Injection. Sulfuric Acid Mist (SAM) emissions are controlled by hydrated lime injection (HLI) on the common duct to all four units just prior to the inlet of the FGD system. HLI is a process to inject powdered hydrated lime into the flue gas stream at the discharge of the booster fans, upstream of the wet/dry interface at the FGD system to reduce aerosol acid mist emissions from the power plant. The acid aerosol mist is created in the combustion process and is also increased across the SCR catalyst (where the catalyst converts SO_2 to sulfur trioxide (SO_3) in the NO_X reduction process). The Air Preheater (APH), ESP and FGD all help remove the acid aerosol mist, but do not necessarily remove it all. When necessary to further reduce SAM (as indicated by the PEMS), the operation of HLI system will reduce the SAM emissions that are generated by the oxidation of fuel sulfur during combustion. SAM reacts with the hydrated lime and

is removed as particulate matter in the downstream FGD system. [Permit Nos. 0330045-028-AC, 0330045-029-AC & 0330045-034-AC]

{Permitting Note: Based on applicant estimates, SAM emissions may be reduced by as much as 66.7% using lime injection and another 25% with the wet FGD system, thus the total reduction of acid mist at the facility is estimated at 75%. This combination of controls is expected to remove approximately 50 tons per year of SAM emissions.}

Emission Limitations and Standards

Unless otherwise specified, the averaging times for **Specific Conditions A.13. – A.18.** are based on the specified averaging time of the applicable test method.

A.13. Visible Emissions.

a. Visible emissions from Units 4 - 7 shall not exceed 20 percent opacity except for one six-minute period per hour during which opacity shall not exceed 27 percent, as determined at the common FGD stack.

b. Visible emissions from unit 015 limestone storage silo baghouses shall not exceed 5% opacity, as demonstrated by annual EPA Method 9 compliance tests.

[Rule 62-296.405(1)(a), F.A.C., Secretarial ORDER(s) signed October 18, 1985, January 3, 1986, May 12, 1988 & June 24, 1988; and, Permit Nos. AO17-211303, Specific Condition 10, AC17-234016, Specific Condition 14, AO17- 171806, Specific Condition 23, 0330045-005-AC, 0330045-023-AC and 0330045-032-AC; 0330045-041-AC]

A.14. Sulfur Dioxide (SO_2).

a. *All Fuels*. Except as provided in item e. below, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input, as measured by applicable compliance methods. [Permit Nos. 0330045-008-AC and 0330045-010-AC]

b. *Solid Fuel*. When burning solid fuel, sulfur dioxide emissions from Unit 006 shall not exceed 38,945 tons per year. [Permit No. 0330045-008-AC]

c. *Liquid Fuel Sulfur Content*. In order to ensure continuous compliance with the sulfur dioxide limit for liquid fuels, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods. [Rule 62-213.440, F.A.C.]

d. *Sulfur Dioxide (SO_2) Limit*. The SO_2 emissions from the combined operation of Units 4, 5, 6 and 7 shall not exceed 886.0 tons during any 30-day rolling total of FGD scrubber operational days (see **Specific Condition A.10.**). [Permit No. 0330045-023-AC]

e. *FGD Bypass Operation*. When operating in FGD bypass mode, SO_2 emissions from all four units combined shall not exceed 25,840 lb/hour (equivalent to 2.1 lb SO_2/MMBtu) based on 3-hour block CEMS averages (or a fuel-based calculation if the CEMS is down).

[Permit No. 0330045-029-AC, Specific Condition A.3.]

A.15. SAM Emissions Cap. As determined by the predictive emissions monitoring system (PEMS) established as part of the hydrated lime injection project, total SAM emissions from Units 4 - 7 (combined) shall not exceed 165.5 tons during any consecutive 12 months, including periods of startup, shutdown, malfunctions and SCR bypass operations. [Rule 62-212.400(12) and Permit No. 0330045-029-AC, Specific Condition A.2.]

A.16. Plant-Wide NO_X Limit. Emissions of nitrogen oxides (NO_X) from the combined operation of Units 4, 5, 6, and 7 shall not exceed 0.2 lb/MMBtu heat input based on a 30-day rolling average. This limit shall apply when either Unit 6 or 7 is on-line. The plant-wide daily NO_X emission rate shall be determined by the following equation:

$$\text{Plant-Wide Daily MMBtu-Weighted } \mathbf{NO_X} \text{ Emission Rate} = \frac{\sum_{\text{Units 4, 5, 6, 7}} [(\text{Unit \# daily MMBtu}) \times (\text{Unit \# daily } NO_X \text{ CEMS Rate})]}{\sum_{\text{Units 4, 5, 6, 7}} (\text{Unit \# daily MMBtu})}$$

The "Unit # daily MMBtu" shall be determined by the daily as-burned fuel analysis and the fuel fired for each unit. The "Unit # daily NO_X CEMS Rate" shall be determined by the daily average of NO_X CEMS data for each unit and reported in terms of "lb/MMBtu heat input". The plant-wide daily NO_X emissions rate shall be determined each day regardless of the operating status for Units 6 or 7. The plant-wide 30-day rolling NO_X average shall be determined for each 30 sequential Unit 6 or 7 operating days, which need not be consecutive. A Unit 6 or 7 operating day means any calendar day that either Unit 6 or 7 operates a minimum of 18 hours. The Unit 6 or 7 daily NO_X CEMS rate may consist of less than 18 hours of data if this is due to: CEMS malfunction or invalid CEMS data. The plant-wide NO_X emission standard shall be achieved by utilizing the SCR systems for Units 6 and 7 and the SNCR systems for Units 4 and 5. [Paragraphs 2, 3 and Exhibit B of the Agreement; Permit Nos. 0330045-005-AC, 0330045-017-AC & 0330045-036-AC, Specific Condition 3]

A.17. Particulate Matter (PM). As determined by CEMS, particulate matter emissions shall not exceed 0.1 pound per million Btu heat input. Compliance with the 0.1 pound per million Btu limit shall be demonstrated by complying with the MATS limit of 0.03 pound per million Btu heat input based on a 30-boiler operating day rolling average in the common FGD stack during normal operations. [40 CFR 63, Subpart UUUUU; Rule 62-296.405(1)(b), F.A.C. and Permit Nos. AC17-234016, Specific Condition 5 and 0330045-041-AC.]

A.18. Particulate Matter - Soot Blowing and Load Change. As determined by CEMS, particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input, during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. [Rule 62-210.700(3), F.A.C. and AC17-234016, Specific Condition 6; 0330045-041-AC.]

Excess Emissions

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

A.19. Excess Emissions - Malfunction. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

A.20. Excess Emissions - Startup or Shutdown. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

A.21. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.22. CAM Plan. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements for sulfuric acid mist (SAM) contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions

limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(8), F.A.C. [40 CFR 64, Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

A.23. SAM Monitoring. The permittee shall monitor compliance with the SAM emissions cap by conducting the required performance tests and using the SAM emission equation based on research conducted by the Electric Power Research Institute (EPRI), which is used in conjunction with the PEMS established as part of the hydrated lime injection project. The applicant shall refine this equation when new site-specific emissions data is available. To provide input data for the PEMS, the actual coal blend sulfur percentage shall be monitored by either the process CEMS at the inlet to the FGD system or by a fuel-based calculation. In addition, the permittee shall monitor the FGD scrubber and hydrated lime injection rates, the plant load, and any other parameters required for the PEMS protocol that are needed to correlate the acid mist reduction efficiency. [Rule 62-213.440, F.A.C.; and, Permit Nos. 0330045-028, Specific Condition A.12., 0330045-029-AC, Specific Condition A.11. & 0330045-036-AC, Specific Condition 4.]

A.24. Bypass Monitoring. The permittee shall continuously monitor the exhaust flow after the bypass dampers to ensure that bypass dampers are effectively sealed or account for emissions under Part 75 protocol until repairs are completed. [Permit No. 0330045-029-AC, Specific Condition A.12. and Applicant Request]

Continuous Monitoring Requirements

{Permitting Note: In accordance with the federal Acid Rain Phase II requirements and Permit No. 0050014-013-AC, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2, urea injection rate and stack gas flow.}

A.25. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous monitoring systems (CEMS) for monitoring Particulate Matter (PM), Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_X) and Carbon Dioxide (CO_2). [Rule 62-296.405(1)(f)1., F.A.C.; and, Permit Nos. AC17-234016, AO17-171806, 0330045-005-AC & 0330045-013-AC; 0330045-041-AC.]

A.26. SO_2 Averaging Time. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see **Specific Condition A.14.**). In the event that valid data capture is not available, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. Fuel sampling shall continue until such time as the valid data capture is restored. In lieu of as fired fuel sampling the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as fired fuel sampling. Maintain a QC program at a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

a. Calibration of CEMS.
b. Calibration Drift (CD) determination and adjustment of CEMS.
c. Preventative maintenance of CEMS (including spare parts inventory).
d. Data recording, calculations and reporting.
e. Accuracy audit procedures including sampling-and analysis methods.
f. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5, 62-296.405(1)(f)1.b., F.A.C., Permit Nos. AC17-234016, AO17-171806 and AO17-211303]

A.27. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

a. In accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 3--Specifications and Test Procedures for CO2 Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 11-- Specifications and Test Procedures for PM Continuous Emission Monitoring Systems in Stationary Sources; or

b. In accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C., 40 CFR 75; and Applicant request]

A.28. NO_X CEMS. To demonstrate compliance with the emissions standards, the permittee shall calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen). The CEMS shall monitor and record data during all periods of Units 004, 005, 006 & 007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. For each calendar quarter, monitor availability shall be 95% or greater. If unable to achieve this level, the permittee shall submit a report identifying the problems in achieving 95% monitor availability and a plan of corrective actions. The permittee shall implement the reported corrective actions within the next calendar quarter. [Permit Nos. 0330045-005-AC-and 0330045-013-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfies this requirement.}

A.29. SNCR Urea Injection Flow Monitors. In accordance with the manufacturer's specifications, the permittee shall have installed, shall keep calibrated, and shall operate and maintain flow meters to measure and record the urea injection rate for the SNCR systems on Units 004 and 005. The permittee shall document the general range of urea flow rates required to meet the NO_X standard over the range of load conditions by comparing NO_X emissions with urea flow rates. During NO_X monitor downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. [Permit Nos. 0330045-013-AC and 0330045-028-AC]

A.30. Continuous Monitoring. Existing Units 4 - 7 are subject to the federal Acid Rain monitoring requirements for stack gas flow rates, and emissions of CO_2, NO_X and SO_2. The permittee shall install, calibrate, operate and maintain continuous emissions monitoring systems in the new common stack to monitor and record the stack gas flow rate and emissions of CO_2, NO_X and SO_2. [Rules 62-4.070 and 62-214, F.A.C.; and, Permit Nos. 0330045-015-AC, 0330045-023-AC, and 0330045-041-AC]

Test Methods and Procedures

A.31. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
3 and or 3A	Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources
17, 5, 5B or 5F	Method for Determining Particulate Matter Emissions (All PM is assumed to be PM_{10}.)

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
8*	Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
25 and or 25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
6, 6A, 6B or 6C	Determination of Sulfur Dioxide
CTM-027	Conditional EPA Test Method 027, Measurement of Ammonia Slip (or equivalent method)

* To demonstrate compliance with the SAM limit specified in this permit, Gulf Power may utilize EPA Method 8; conditional test methods: CTM-013, CTM-013A or CTM-013B, as appropriate; or, other test methods as approved through the Department's alternate sampling procedure (ASP) protocol.

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C., Permit Nos. 0330045-005-AC and 0330045-029-AC]

A.32. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.33. Annual Compliance Tests Required. Except as provided in Appendix ASP 97-B-01 (attached), during each calendar year (January 1st to December 31st), in accordance with the requirements listed below and to demonstrate compliance with the emission limits in **Specific Condition A.13.**: Units 004 - 007 shall be tested for VE during normal operations at the common FGD exhaust stack; and, Unit 015 shall be tested for VE. [Rule 62-297.310(8), F.A.C., Permit Nos. 0330045-005-AC, 0330045-023-AC and 0330045-028-AC; 0330045-041-AC.]

{Permitting Note: The annual SO_2 and NO_X tests that are required by Rule 62-297.310(8), F.A.C., can be done during the annual RATAs as satisfaction of this requirement, provided all other testing requirements specified in the permit are met. Once CEMS are installed and operational in the bypass stacks and continuous compliance can be demonstrated, completion of the annual RATAs will replace the need for SO_2 or NO_X stack tests.}

A.34. Compliance Tests Prior To Renewal. The annual compliance tests required in **Specific Condition A.33.** satisfy the requirements contained in Rule 62-297.310(8), F.A.C., for testing prior to renewal. [Rules 62-210.300(2)(a) and 62-297.310(8), F.A.C.]

A.35. Visible Emissions. The test method for visible emissions shall be EPA Method 9, incorporated in Chapter 62-297, F.A.C. [Rules 62-213.440 and 62-296.405(1)(e)1, F.A.C.; 0330045-041-AC.]

A.36. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used, the front half filter temperature shall be 160° ±14 °C (320° ±25 °F) Acetone wash shall be used with EPA Method 5. [Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310 F.A.C.; 40 CFR Appendix Table 5 to Subpart UUUUU of Part 63, Performance Testing Requirements. Table 5 to Subpart UUUUU of Part 63 - Performance Testing Requirements]

A.37. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B or 6C,

incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. [Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310, F.A.C.; and, Permit Nos. AC17-234016, AO17-171806 and AO17-211303.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.)}

A.38. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, ASTM D1552-(latest edition), both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel following each fuel delivery.

b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.

c. Determine and record the density (using ASTM D 1298-80, ASTM D4052-(latest edition) or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.

d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and ASTM D5865-(latest edition), or the latest edition.

e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.

f. Utilize the information in a., b., c., d. and e., above, to calculate the SO2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.39. Heat Input. Compliance with the heat input limitations specified in **Specific Condition A.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in **Specific Condition A.38.c. & d.**) (see **Specific Condition A.47.**). The permittee may use vendor supplied data to determine the heat content of the natural gas. Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) and the natural gas vendor's information shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request. [Permit No. 0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

A.40. SAM. The permittee shall demonstrate compliance with the SAM emissions cap by conducting the required performance tests and using the SAM emission equation based on research conducted by the Electric Power Research Institute (EPRI), which is used in conjunction with the PEMS established as part of the hydrated lime injection project. The applicant shall refine this equation when new site-specific emissions data is available. [Rule 62-213.440, F.A.C.; and, Permit Nos. 0330045-028, Specific Condition A.12. & 0330045-029-AC, Specific Condition A.11.]

A.41. Additional SAM Compliance Tests. If the actual coal blend sulfur specification increases by 0.30 lb SO_2/MMBtu or more based on a 30-day average above the current maximum tested coal blend sulfur specification, the permittee shall conduct new "SAM Performance Stack Tests" at the stack (or in ductwork after the FGD system) to determine SAM emissions within the following load ranges: 40% to 50%; 50% to 60; 70% to 80%; 80% - 90%; and greater than 90%. Within each range, the permittee shall conduct at least two test runs to determine SAM emissions. One test run shall be with the HLI system "on" and one test run shall be conducted with the HLI system "off". For each load range, multiple tests may be conducted at varying HLI rates. The tests shall be conducted within 45 days of determining that the actual coal blend sulfur specification increased by 0.30 lb SO_2/MMBtu or more based on a 30-day average.

(a) *SAM Test Reports*. Within 45 days after completing the performance tests, the permittee shall submit a test report summarizing the results. For each test run, the report shall also indicate: the fuel firing rate of each unit; heat input rate of each unit; hydrated lime injection rate; controlled SO_2 emission rate based on CEMS; uncontrolled SO_2 emission rate in lb/MMBtu based on the process CEMS at the inlet to the FGD system (or a fuel-based calculation if the CEMS is down); ammonia injection rates for SCR (Units 6 and 7); and ammonia injection rates for SNCR (Units 4 and 5). Within 90 days after completing the performance tests, the permittee shall submit a second report summarizing the following:

(1) Identify each set of operating conditions and parameters evaluated;

(2) Identify the relative influence of each operating condition or parameter;

(3) Describe how the control system will adjust the HLI rate based on the given operating condition or parameter; and Show how the information will be used to adjust the equation in order to estimate SAM emissions based on different operating conditions, parameters and HLI rates.

(b) Data Collected for SAM Performance Tests. The operator shall use best efforts to maintain the designated heat input rate throughout each SAM performance test run. During each test run, the following information shall be recorded: fuel firing rate of each unit; heat input rate of each unit; hydrated lime injection rate; controlled SO2 emission rate based on CEMS; uncontrolled SO2 emission rate in lb/MMBtu based on a fuel-based calculation; ammonia injection rates for SCR on Units 6 and 7; and ammonia injection rates for SNCR on Units 4 and 5.

(c) SAM Summary Report. A summary report shall be submitted to the Office of Permitting and Compliance and the Compliance Authority for each set of SAM performance tests (Stack Tests). Each report shall: summarize the emissions, monitoring and operational data collected; evaluate the SAM emissions for the given conditions; identify the impacts of the control equipment; and provide a discussion for refining the SAM equation.

[Permit Nos. 0330045-029-AC, Specific Conditions A.6., A.8., A.10., A.13. & A.14. and 0330045-036-AC, Specific Condition 4; 0330045-041-AC.]

Recordkeeping and Reporting Requirements

A.42. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Excess Emissions	Quarterly	**A.44.**
Test Reports	Annually	**A.45.**

A.43. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

A.44. Excess Emission Reports. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.45. Test Reports. The permittee shall prepare and submit reports for all required tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. For each required test run, the report shall indicate the actual heat input rate (MMBtu/hour), the NO_X emission rate (lb/MMBtu) as recorded by the CEMS, and the urea injection rate (lb/hour). The report shall also include copies of the continuous monitoring records for the NO_X emissions. (See also Appendix TR8.) [Rule 62-297.310(8), F.A.C. and Permit No. 0330045-011-AC]

A.46. Hours of Operation Log. For each emissions unit, the permittee shall maintain an operation log available for Department inspection that documents the total hours of annual operation, including a detailed account of the hours operated on each of the allowable fuels. [Rule 62-213.440, F.A.C.]

A.47. Fuel Consumption Log. The owner or operator shall maintain daily records of fuel consumption and each analysis that provides the heating value and sulfur content for all fuels fired. These records must be of sufficient detail to determine compliance with the allowable sulfur dioxide emission limitations. [Rules 62-213.440 & 62-4.070(3), F.A.C.]

{Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

A.48. CEMS Maintenance Log. A maintenance log of the continuous monitoring systems shall be kept showing:

a. Time out of service.

b. Calibration and adjustments.

[Rule 62-213.440, F.A.C. and AO17-211303, Specific Condition 16]

A.49. Long Term Scrubber Bypass. EPA approval allows Plant Crist to include emissions from natural gas bypass operations in the bypass stacks (CS1BYP & CS2BYP) with controlled emissions from the common scrubber stack (CS1FGD) for MATS 30 day compliance averages. In summary as outlined in EPA authorization letter, Plant Crist will operate and report MATS related emissions as follows:

1.(a) In lieu of reporting deviations in the bypass stacks (CS1BYP & CS2BYP) for mercury and PM continuous monitoring during bypass events when each attributing unit is combusting only natural gas (as confirmed by fuel usage) and when SO_2 concentrations are less than 25 ppmv (hourly average as measured by the corresponding bypass stack CEMS), Plant Crist will report PM and mercury emissions using a site-specific emission factor as described below. EPA is requiring a stricter standard to identify natural gas usage to ensure complete accounting of the emissions from coal combustion. In the event that the SO_2 CEMS is offline or considered "out of control," the first 4 hours of any bypass event shall be considered a monitoring deviation regardless of the fuel usage. Please note, the "attributing units" for bypass stack CS1BYP are Units 4 and 5 and the "attributing units" for bypass stacks CS2BYP are Units 6 and 7.

1.(b) In lieu of reporting deviations for SO_2 monitoring during bypass events (CS1BYP & CS2BYP) when each attributing unit is combusting only natural gas, Plant Crist is permitted to use the SO_2 CEMSs installed on the bypass stacks to show compliance with the SO_2 surrogate alternative and may also be used as part of Plant Crist's 30-day SO_2 rolling average. If the SO_2 concentrations should reach 25 ppmv or greater (hourly average as measured by the corresponding bypass stack CEMS), then Plant Crist must report a deviation for the SO_2 monitoring.

2. When combusting natural gas during planned/unplanned bypass events due to FGD malfunction or maintenance as defined above, Plant Crist may report a PM site-specific value of 0.010 lb/mmBtu and mercury site-specific value of 0.165 lb/TBtu. Site specific values may also be used as part of Plant Crist's 30-day rolling average as long as criteria 1(a) above has been met. The current site-specific emissions factors are valid until January 1, 2017, by this date and thereafter, site-specific emission factors must be determined using periodic emission testing as follows:

   a. Conduct emission testing on one of the bypass stacks while operating on natural gas. Emission testing must be conducted while the units are operating within 10 percent of the combined highest heat input (mmBtu/hr) while combusting natural gas for the previous 8 calendar quarters. Testing must be repeated at least once every 8 calendar quarters.

   b. Crist must conduct PM testing in triplicate according to 40 CFR part 60,Appendix A, Method 5; the front half filter temperature shall be 160° ±140C (3200 ±250F), while collecting a minimum of 2 dscm per sample.

   c. Crist must conduct mercury testing in triplicate according to 40 CFR part 60, Appendix A, Method 30B. Due to the expected concentrations, you must collect a minimum of 100 dry liters per sample.

[Rule 62-4.070(3), F.A.C. and Permit No. 0330045-023-AC]

Miscellaneous Conditions

A.50. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. *On-specification Used Oil Emissions Limitation*. This emissions unit is permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 part per million (ppm). On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil, which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. *Quantity Limitation*. This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (004, 005, 006 and 007).

c. *PCB Limitation*. 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. *Operational Requirement*. 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 Requirements*. For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel: A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications. [40 CFR 279.72(a)]

Testing of used oil fuel: Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(1) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.

(2) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(3) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs. [40 CFR 761.20(e)(2)]

When testing is 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 and PCBs.

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).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see **Specific Conditions A.38.** and **A.39.**).

f. *Record Keeping Requirement.* 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:

(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and

(2) (or each deposit of used oil, results of the analyses as required by the above conditions, or

(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. *Reporting Requirements.* The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year. [Rules 62-4.070(3), 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted]

Mercury Research Center Conditions

A.51. Final Notification and Removal. Notification shall occur within 45 days, in writing, upon completion of the final test. Prior to removal of the mercury research center, the permittee shall have provided the DEP Northwest District Office and the Office of Permitting and Compliance with its plans to disassemble and remove all slipstream components, returning the unit back to its original condition.
[Permit Nos. 0330045-011-AC and 0330045-028-AC, Specific Condition A.2.]

40 CFR 63, Subpart UUUUU Requirements

A.52. Subpart UUUUU Requirements. In addition to the emissions limits shown above, the permittee shall also comply with the following emissions limits

{Permitting Note: On December 9, 2015, EPA approved an alternative sampling procedure and reporting requirements to the MATS rule for bypass operations when burning natural gas. The conditions authorized in EPA's approval letter (Appendix MATS) are incorporated by reference only in this Title V air operation permit.}

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

(1)Antimony (Sb) - 0.80 pounds per terra Btu (lb/TBtu) or 8.0 x 10^{-3} lb/GWh.

(2)Arsenic (As) - 1.1 lb/TBtu or 0.020 lb/GWh.

(3)Beryllium (Be) - 0.20 lb/TBtu or 2.0 x 10^{-3} lb/GWh.

(4)Cadmium (Cd) - 0.30 lb/TBtu or 3.0 x 10^{-3} lb/GWh.

(5)Chromium (Cr) - 2.8 lb/TBtu or 0.030 lb/GWh.

(6)Cobalt (Co) - 0.80 lb/TBtu or 8.0 x 10^{-3} lb/GWh.

(7)Lead (Pb) - 1.2 lb/TBtu or 0.020 lb/GWh.

(8)Manganese (Mn) - 4.0 lb/TBtu or 0.050 lb/GWh.

(9)Nickel (Ni) - 3.5 lb/TBtu or 0.040 lb/GWh.

(10)Selenium (Se) - 5.0 lb/TBtu or 0.060 lb/GWh.

The permittee has chosen to show compliance with the Particulate Matter standard listed above using a Particulate Monitor CEMS as described in **Conditions A.17, A.25 and A.27** and shall not be required to meet the total non-Hg HAP metals emission limit or the individual HAP metal limits as listed above in a.(1)-(10) (40 CFR Appendix Table 2 to Subpart UUUUU of Part 63, Emission Limits for Existing EGUs).

b. *Hydrogen Chloride (HCl)*. Emissions of HCl shall not exceed either 2.0 x 10-3 lb/MMBtu or 0.020 lb/MWh. In lieu of HCl emission limit, the permittee may select to meet a SO_2 emission limit of either 0.20 lb/MMBtu or 1.5 lb/MWh 30-boiler operating day rolling average in the common FGD stack during normal operations.

The permittee has chosen to comply with the HCl standard listed above using by meeting the SO_2 emission limit as listed above using SO_2 CEMS as described in **Conditions A.25, A.26, and A.27** and shall not be required to meet HCl emission limit above (40 CFR Subpart UUUUU 63.9991, 40 CFR Appendix Table 2 to Subpart UUUUU of Part 63, Emission Limits for Existing EGUs).

c. *Mercury (Hg)*. Emissions of Hg shall not exceed either 1.2 lb/TBtu or 0.013 lb/GWh 30-boiler operating day rolling average in the common FGD stack during normal operations.

Compliance with the above emissions limits shall be demonstrated pursuant to one of the available options specified in 40 CFR 63, Subpart UUUUU (see attached Appendix 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units). The permittee shall also comply with the recordkeeping and reporting requirements and all other applicable requirements specified Subpart UUUUU. [40 CFR 63 Subpart UUUUU and EPA approval letter dated December 9, 2015]

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

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

EU No.	Brief Description
008	Fly Ash Storage Silo A - Northern Most Vent Fly Ash Storage Silo B - Southern Most Vent Fly Ash Storage Silo C (Associated with Unit 007 SCR)

This emissions unit consists of two Fly Ash Storage Silos, A-Northern most vent and B-Southernmost vent. The fly ash collection systems from the precipitators on boiler numbers 4, 5, 6 and 7, which deliver fly ash to the three transfer tanks, are totally enclosed (i.e. no emission points). Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settles by gravity upon entering the silo and the residua1 particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported off-site in closed tanker trucks (approximately 20% sold annually) or conditioned fly ash (12-15% water added) will be transported to an approved landfill area on-site.

Silo C is used for temporary storage of SCR ash. This is primarily ash that would be caught by the precipitator but falls out due to the tall vertical duct at the SCR inlet. Also, economizer ash, which is a large coarse gravel-like ash (more like bottom ash than fly ash), is transported to the C silo for Unit 7 only. Air locks are used to drop the ash into piping where it is blown to the C silo, which is equipped with a small vented bag house. This silo holds the ash until it can be loaded into a truck for transportation to either off-site use or to the plant's landfill. Note this silo receives approximately 1% or less of the Unit 007 ash and more of that ash gravity settles due to the large size.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required, and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Each silo has two vents. Stack height = 124.5 feet, exit dimensions = 18" x 24" rectangle, exit temperature = 100 ºF, actual volumetric flow rate = 5,452 acfm per vent, velocity = 30 feet per second. The two silos were built between October 27, 1981 and June 1, 1983.}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operating rate for Unit 008 is 150 tons per hour of fly ash transported to either or both silos. [Rules 62-4.160(2), 62-210.200(PTE), F.A.C. and Permit No. AC17-47675]

B.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements and **Specific Condition B.12.** [Rule 62-297.310(3), F.A.C.]

B.3. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for **Specific Condition B.4.** is based on the specified averaging time of the applicable test method.

B.4. Visible Emissions. Visible emissions from each baghouse vent (2 on each baghouse) shall be less than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C. and Permit No. AC17-47675]

Excess Emissions

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

B.5. Excess Emissions Allowed. Excess emissions from this emissions unit resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are

adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rules 62-210.700(1), F.A.C.]

B.6. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rules 62-210.700(4), F.A.C.]

Test Methods and Procedures

B.7. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C. and Permit No. 0330045-005-AC]

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

B.9. Annual Compliance Tests Required. During each federal calendar fiscal year (January 1st to December 31th), emissions Unit 008 shall be tested to demonstrate compliance with the emissions standards for visible emissions (VE). [Rule 62-297.310(8)a.1, F.A.C.]

B.10. Compliance Tests Prior To Renewal. Compliance tests shall be performed for VE once every 5 years. The tests shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limits in **Specific Condition B.4.** [Rules 62-210.300(2)(a) and 62-297.310(8), F.A.C.]

B.11. Visible emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

B.12. **Not federally enforceable.** Operating Rate During Testing. Compliance shall be demonstrated at an operating rate which typifies normal operation of the fly ash system. This operating rate may be lower than the maximum allowable operating rate. Should the Department feel that test results do not provide reasonable assurance that the source is capable of compliance at the permitted maximum operating rate, the Department may request that a visible emissions test be conducted at a higher operating rate up to the maximum allowable operating rate. [January 16, 1984 letter modifying Permit No. AO17-70422, Specific Condition 15]

Recordkeeping and Reporting Requirements

B.13. Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for reporting requirements. [62-213.440, F.A.C.]

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Subsection C. Emissions Unit 014

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

E.U. ID No.	Brief Description
014	Mechanical Draft Cooling Tower with a maximum circulation rate of 190,000 GPM.

The mechanical draft cooling tower (EU 014) for Unit 007 is comprised of 14 cells. It has a width of 105 feet, a length of 367.5 feet, and a height of 68 feet, includes drift eliminators rated at 0.0005%, and operates at a maximum brackish-water flow rate of 190,000 gallons per minute (GPM) for all cells combined. Brackish water is sprayed through the tower where fan induced air flow causes evaporative cooling. Water vapor, saltwater droplets (drift) and salt particles are emitted. Drift emissions are controlled by drift eliminators.

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

Emissions And Performance Requirements

C.1. Hours of Operation. The new cooling tower shall be allowed to operate 8,760 hours per year. [Rule 62-210.200 (PTE), F.A.C. and Permit No. 0330045-019-AC]

C.2. Cooling Tower Design. The cooling tower was designed and shall be maintained to achieve a drift rate of no more than 0.0005% of the circulating water flow. [Permit No. 0330045-019-AC]

{Note: This equates to an estimated average emission rate of particulate matter (PM) from the cooling tower at 0.87 pounds per hour and 3.82 tpy, based on an average TDS rate of 1,935 ppm. The PM_{10} emissions are estimated to be approximately 60% of the estimated particulate matter emission rate.}

C.3. Circulating Water Flow Rate. Upon request, the applicant shall provide a means for determining the circulating water flow rate through the new cooling tower. [Rule 62-4.070, F.A.C.]

{Note: This emissions unit is not subject to a visible emissions limitation. Emissions from this emissions unit include water droplets, so visible emission testing is not possible.}

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

E.U. ID No.	Brief Description of Engines
017	• Four Deutz diesel engine driven emergency sump pumps used to back up the permanently mounted electrical pumps, 1,800 rpm - 46 HP. • John Deere diesel engine driven building emergency sump pump, 2,000 rpm - 139 HP. • Mitsubishi diesel engine driven emergency generator-Turbine Floor, 1,800 rpm - 898 HP. • Emergency Generator - Scrubber Make-up Pump, 220 HP.

This section addresses seven emergency compression ignition (CI) reciprocating internal combustion engines (RICE).

Emissions Unit 017 consists of four 46 HP diesel engine driven emergency sump pumps used to back up the permanently mounted electrical pumps, a 139 HP John Deere diesel engine driven emergency building sump pump, an 898 HP Mitsubishi diesel engine driven emergency generator (turbine floor) and a 220 HP Emergency Generator for the Scrubber Make-up Pump. These engines use ultra-low sulfur diesel fuel only. Air pollutant emissions from these engines are uncontrolled.

The following table provides important details for these engines:

Engines Description	Engine Brake HP	Model Year	Type of Engine	Displacement liters/cylinder (l/c)	Manufacturer & Model No.
Coal Yard Sump Pump No.1	46 HP (34.5 kW)	Fall 2006	Compression Ignition Emergency Pump	3.109L	Deutz 6DZXL03.1041
Coal Yard Sump Pump No.2					
Coal Yard Sump Pump No.3					
Unit 4/5 Building Sump Pump					
Unit 7 Building Sump Backup Pump	139 HP (104 KW)	Fall 2006	Compression Ignition Emergency Pump	1.7 l/c	John Deere 6068TF275C,G,I
Emergency Generator (Turbine Floor)	898 HP (670 kW)	Fall 2006	Compression Ignition Emergency Generator	4.085 l/c	Mitsubishi 56R-Y1PTA-4
Emergency Generator for Scrubber Make-up Pump	220 HP (164 KW)	2010	Compression Ignition Emergency Generator	< 10	John Deere AJDXL09.0102

{Permitting Note: These emergency use compression ignition reciprocating internal combustion engines (CI RICE) are regulated under 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE and 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition RICE, adopted in Rules 62.204.800(11)(b) & (8)(b), F.A.C., respectively. This permit section addresses "new" stationary CI RICE, with a displacement less than 10 liters per cylinder, that are located at a major source of HAP and that have been modified, reconstructed or commenced

construction on or after 6/12/2006. In accordance with provisions of section 63.6590(c)(6) meeting the requirements of 40 CFR 60, Subpart IIII satisfies compliance with 40 CFR 63, Subpart ZZZZ.}

Essential Potential to Emit (PTE) Parameters

D.1. Authorized Fuel. These Stationary Reciprocating Internal Combustion Engines (RICE) must use diesel fuel that meets the following requirements for non-road diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted:

a. *Sulfur Content*. The sulfur content shall not exceed = 15 ppm = 0.0015% by weight (ultra-low sulfur) for non-road fuel.

b. *Cetane and Aromatic*. The fuel must have a minimum cetane index of 40 or must have a maximum aromatic content of 35 volume percent.

[40 CFR 60.4207(b), 80.510(c), 80.510(f)(2) and 80.510(f)(7)]

{Permitting Note: Compliance with the above requirements can be demonstrated through the use of vendor delivery receipts.}

D.2. Restricted Hours of Operation.

a. *Emergency Situations*. There is no time limit on the use of emergency stationary RICE in emergency situations. [40 CFR 60.4211(f)(1)]

b. *Other Situations*. You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs b.(1) through (3) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph **c.** counts as part of the 100 hours per calendar year allowed by this paragraph.

(1) Maintenance and Testing. Each RICE is authorized to operate for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year. [40 CFR 60.4211(f)(2)(i)]

(2) Emergency Demand Response. Each RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. [40 CFR 60.4211(f)(2)(ii)]

(3) Voltage or Frequency Deviations. Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. [40 CFR 60.4211(f)(2)(iii)]

c. *Non-emergency Situations*. These emergency RICE may be operated for up to 50 hours per calendar year in nonemergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph **b.**, above. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. [40 CFR 60.4211(f)(3)]

Emissions Standards

D.3. 46 HP Deutz Sump Pump Engines. Emissions from these engines shall not exceed the following:

a. *NMHC + NO_X Emissions.* Non-methane hydrocarbons plus nitrogen oxide emissions shall not exceed 9.5 grams per kilowatt hour (g/KW-hr) (7.1 grams per horsepower-hour (g/HP-hr)) for each engine.

b. *CO Emissions*. Carbon monoxide emissions shall not exceed 5.5 g/KW-hr (4.1 g/HP-hr) for each engine.

c. *PM emissions*. Particulate matter emissions shall not exceed 0.8 g/KW-hr (0.60 g/HP-hr) for each engine.

[40 CFR 60.4205(a) and Table 1 to 40 CFR 60, Subpart IIII]

D.4. 139 HP John Deere Sump Pump Engine. Nitrogen oxide (NO_X) emissions from this engine shall not exceed 9.2 g/kW-hr (6.9 g/HP-hr). [40 CFR 60.4205(a) and Table 1 to 40 CFR 60, Subpart IIII]

D.5. 898 HP Mitsubishi Generator Engine. Emissions from this engine shall not exceed the following:

a. *HC Emissions*. Hydrocarbon emissions shall not exceed 1.3 g/KW-hr (1.0 g/HP-hr).

b. *NO_X Emissions.* Nitrogen oxide emissions shall not exceed 9.2 g/KW-hr (6.9 g/HP-hr).

c. *CO Emissions*. Carbon monoxide emissions shall not exceed 11.4 g/KW-hr (8.5 g/HP-hr).

d. *PM emissions*. Particulate matter emissions shall not exceed 0.54 g/KW-hr (0.40 g/HP-hr.

[40 CFR 60.4205(a) and Table 1 to 40 CFR 60, Subpart IIII]

D.6. 220 HP John Deere Generator Engine. Emissions from this engine shall not exceed the following:

a. *NMHC + NO_X Emissions.* Non-methane hydrocarbons plus nitrogen oxide emissions shall not exceed 4.0 g/KW-hr.

b. *CO Emissions*. Carbon monoxide emissions shall not exceed 3.5 g/KW-hr.

c. *PM emissions*. Particulate matter emissions shall not exceed 0.20 g/KW-hr.

[40 CFR 60.4205(b), 4202(a)(2) & 40 CFR 89.112, Table 1]

Testing and Compliance Requirements

D.7. Operation and Maintenance. Except as permitted in Specific Condition **D.10.**, over the entire life of the engine, the owner or operator must:

a. Operate and maintain the stationary CI internal combustion engine according to the manufacturer's emission-related written instructions;

b. Change only those emission-related settings that are permitted by the manufacturer; and

c. Meet the emissions limits in **Specific Conditions D.3. - D.6.**

[40 CFR 60.4206 and 40 CFR 60.4211(a) & (g)]

D.8. Pre-2007 Engine Compliance Requirements. For the 46 HP Deutz, the 139 HP John Deere and the 898 HP Mitsubishi engines, you must demonstrate compliance according to one of the methods specified in paragraphs a. through e.

a. Having purchased an engine certified according to 40 CFR Part 89 or 40 CFR Part 94, as applicable, for the same model year and maximum engine power. The engine must have been installed and configured according to the manufacturer's specifications.

b. Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in Specific Condition D.11**.** and these methods must have been followed correctly.

c. Keeping records of engine manufacturer data indicating compliance with the standards.

d. Keeping records of control device vendor data indicating compliance with the standards.

e. Conducting an initial performance test to demonstrate compliance with the emission standards in **Specific Conditions D.3. – D.5.**, as applicable, according to the requirements specified in **Specific Condition D.11.**

[40 CFR 60.4211(b)

D.9. 220 HP John Deere Engine Compliance/Certification Requirements. For this engine, you must comply with the emissions standards specified in **Specific Condition D.6.** by having purchased an engine certified by the manufacturer to meet those limits. The engine must have been installed and configured according to the manufacturer's emission-related specifications, except as permitted in **Specific Condition D.10.** [40 CFR 60.4211(c) & (g)]

D.10. Failure to Follow Manufacturer's Emission-related Written Instructions. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

a. *46 HP Deutz Engines*. You must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action. [40 CFR 60.4211(g)(1)]

b. *139 & 200 HP John Deere Engines.* You must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. [40 CFR 60.4211(g)(2)]

c. *898 HP Mitsubishi Engine.* You must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards. [40 CFR 60.4211(g)(3)]

D.11. Testing Requirements. In the event performance tests are required pursuant to **Specific Condition D.10.**, the following requirements shall be met:

a. *Testing Procedures*. The performance test must be conducted according to the in-use testing procedures in 40 CFR Part 1039, Subpart F. Link to Subpart F

b. *NTE Standards.* Exhaust emissions from these engines must not exceed the not-to-exceed (NTE) numerical requirements, rounded to the same number of decimal places as the applicable standards (STD) in Specific Conditions **D.3. - D.6.**, determined from the following equation:
NTE Requirement For Each Pollutant = (1.25) x (STD) (Eq. 1)

Alternatively, EU 011 (pre-2007) may follow the testing procedures in 40 CFR 60.4213, as appropriate. Link to 40 CFR 60.4213

[40 CFR 60.4212(a), (c) & (d)]

D.12. Common Testing Requirements. Unless otherwise specified and if required, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

Monitoring Requirements

D.13. Hour Meter. The owner or operator must install a non-resettable hour meter if one is not already installed. [40 CFR 60.4209(a)]

Recordkeeping Requirements

D.14. Hours of Operation Records. Owner or operator must keep records of the operation of the engine in emergency and non-emergency services that are recorded through the non-resettable hour meter. The owner or operator must record the time of operation of the engine and the reason the engine was in operation during that time. [Rule 62-213.440(1), F.A.C.]

D.15. Maintenance Records. To demonstrate conformance with the manufacturer's emission-related written instructions for operation and maintenance and to document when compliance testing must be performed pursuant to **Specific Condition D.10.**, the owner or operator must keep the following records:

a. Engine manufacturer documentation and/or certification indicating compliance with the standards.

b. A copy of the manufacturer's written instructions for operation and maintenance of the engines.

c. A written maintenance log detailing the date and type of maintenance performed on the engines, as well as any deviations from the manufacturer's written instructions.

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

D.16. Testing Notification. At such time that the requirements of Specific Condition **D.11.** become applicable, the owner or operator shall notify the compliance authority of the date by which the initial compliance test must be performed. [Rule 62-213.440(1), F.A.C.]

D.17. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

General Provisions

D.18. 40 CFR 60 Subpart A, General Provisions. The owner or operator shall comply with the applicable requirements of 40 CFR 60, Subpart A - General Provisions, as specified below. Link to 40 CFR 60, Subpart A - General Provisions

General Provisions Citation	Subject of Citation
§ 60.1	General applicability of the General Provisions
§ 60.2	Definitions (see also § 60.4219)
§ 60.3	Units and abbreviations
§ 60.4	Address
§ 60.5	Determination of construction or modification
§ 60.6	Review of plans
§ 60.8	Performance tests (if required)
§ 60.9	Availability of information
§ 60.10	State Authority
§ 60.12	Circumvention

General Provisions Citation	Subject of Citation
§ 60.14	Modification
§ 60.15	Reconstruction
§ 60.16	Priority list
§ 60.17	Incorporations by reference
§ 60.19	General notification and reporting requirements

[40 CFR 60.4218 and Table 8 to 40 CFR 60, Subpart IIII]

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

E.U. ID No.	Brief Description of Engine
018	• Four Cummins 325 HP Diesel Engine Driven Emergency Fire Pumps • One Cummins 300 HP Diesel Engine Driven Emergency Fire Pump

Emissions Unit 018 consists of five compression ignition (CI) diesel engine driven reciprocating internal combustion engines (RICE) used to power emergency fire pumps. Four of the engines are 325 HP and one of the engines is 300 HP. Air pollutant emissions from these engines are uncontrolled.

The following table provides important details for these five Cummins diesel engine driven emergency fire pumps:

Engine Identification	Engine Brake HP	Date of Construction	Displacement liters/cylinder (l/c)	Cummins Engine No.	Model No.
Diesel Fire Pump # 1 (4/5 Cooling Tower)	325 HP (246 KW)	1975	3.5 l/c	10486203	1NT855F2
Diesel Fire Pump # 2 (4/5 Cooling Tower)	325 HP (246 KW)	1976	3.5 l/c	10486204	1NT855F2
Diesel Fire Pump # 3 (Main Fire House)	325 HP (246 KW)	1976	3.5 l/c	10536206	1NT855F2
Diesel Fire Pump # 4 (Main Fire House)	325 HP (246 KW)	1976	3.5 l/c	10538713	1NT855F2
Diesel Fire Pump # 7 (Unit 4/5 Intake Canal Structure)	300 HP (224 KW)	1987	3.5 l/c	11422551	NT855F3

{Permitting Note: These compression ignition reciprocating internal combustion engines (CI RICE) are regulated under 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) adopted in Rule 62.204.800(11)(b), F.A.C. This permit section addresses "existing" emergency stationary CI RICE less than or equal to 500 HP with a displacement of less than 10 liters per cylinder that are located at a major source of HAP and that have not been modified or reconstructed after 6/12/2006. If the RICE are modified or reconstructed after 7/11/2005, the NSPS 40 CFR 60, Subpart IIII, will then apply.

Essential Potential to Emit (PTE) Parameters

E.1. Hours of Operation.

a. *Emergency Situations*. There is no time limit on the use of emergency stationary RICE in emergency situations. [40 CFR 63.6640(f)(1)]

b. *Other Situations*. You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs b.(1) through (3) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph c.(1) counts as part of the 100 hours per calendar year allowed by this condition.

(1) Maintenance and Testing. Each RICE is authorized to operate for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local

government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year. [40 CFR 63.6640(f)(2)(i)]

(2) Emergency Demand Response. The emergency engines may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. [40 CFR 63.6640(f)(2)(ii)]

(3) Voltage or Frequency Deviations. The emergency generator may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. [40 CFR 63.6640(f)(2)(iii)]

c. *Non-emergency Situations*. These units may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph b., above. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. [40 CFR 63.6640(f)(3)]

Emission Limitations and Operating Requirements

E.2. Work or Management Practice Standards.

a. *Oil*. Change oil and filter every 500 hours of operation or annually, whichever comes first. [40 CFR 63.6602 & Table 2c.1.a.]

b. *Air Cleaner*. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary. [40 CFR 63.6602 & Table 2c.1.b.]

c. *Hoses and Belts*. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. [40 CFR 63.6602 & Table 2c.1.c.]

d. *Operation and Maintenance*. Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions or develop and follow your own maintenance plan which must provide, to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e)(2) & Table 6.9.].

e. *Engine Startup*. During periods of startup the owner or operator must minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63.6625(h) and Table 2c]

f. *Oil Analysis*. The owner or operator has the option of using oil analysis to extend the oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in paragraph a., of this condition. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis

are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [40 CFR 63.6625(i)]

Monitoring of Operations

E.3. Hour Meter. The owner or operator must install a non-resettable hour meter if one is not already installed. [40 CFR 63.6625(f)]

Compliance

E.4. Continuous Compliance. Each unit shall be in compliance with the emission limitations, operating limitations, and other requirements in this section at all times. [40 CFR 63.6605(a)]

E.5. Operation and Maintenance of Equipment. At all times the owner or operator must operate and maintain, any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the compliance authority which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Recordkeeping Requirements

E.6. Notification, Performance and Compliance Records. The owner or operator must keep:

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

b. Records of the occurrence and duration of each malfunction of operation.

c. Records of all required maintenance performed on the hour meter.

d. Records of actions taken during periods of malfunction to minimize emissions in accordance with Specific Condition **E.5.**, including corrective actions to restore malfunctioning process and monitoring equipment to its normal or usual manner of operation.

e. Records of the actions required in specific condition **E.2.d.** to show continuous compliance with each emission limitation or operating requirement.

f. Records of the Work or Management Practice Standards specified in Specific Condition **E.2.**

g. Records of the maintenance conducted in order to demonstrate that the RICE was operated and maintained according to your own maintenance plan.

h. Records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for emergency demand response operation or for periods of voltage or frequency deviations, the owner or operator must keep records of the notification of the emergency situation, and the time of engine operation for these purposes.

[40 CFR 63.6655]

E.7. Records Retention.

a. The owner or operator must keep records in a suitable and readily available form for expeditious reviews.

b. The owner or operator must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660 and 40 CFR 63.10(b)(1)]

Reporting Requirements

E.8. Delay of Performing Work Practice Requirements. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in specific condition **E.2.** of this section, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. [40 CFR 63, Subpart ZZZZ, Table 2c, footnote 1]

General Provisions

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

General Provisions Citation	Subject of Citation
§63.1	General applicability of the General Provisions
§63.2	Definitions (Additional terms defined in §63.6675)
§63.3	Units and abbreviations
§63.4	Prohibited activities and circumvention
§63.5	Construction and reconstruction
§63.6(a)	Applicability
§63.9(a)	Applicability and State delegation of notification requirements
§63.9(b)(1)–(5)	Initial notifications. Except that §63.9(b)(3) is reserved.
§63.9(i)	Adjustment of submittal deadlines
§63.9(j)	Change in previous information
§63.10(a)	Administrative provisions for recordkeeping/reporting
§63.10(b)(1)	Record retention
§63.10(b)(2)(vi)–(xi)	Records
§63.10(b)(2)(xii)	Record when under waiver
§63.10(b)(2)(xiv)	Records of supporting documentation
§63.10(b)(3)	Records of applicability determination
§63.10(d)(1)	General reporting requirements
§63.10(f)	Waiver for recordkeeping/reporting
§63.12	State authority and delegations
§63.13	Addresses
§63.14	Incorporation by reference
§63.15	Availability of information

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

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Operated by: Gulf Power Company
Plant: Crist Electric Generating Plant
ORIS Code: 0641.

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

E.U. ID No.	Brief Description	
004	Boiler Number 4 - 1,096.7 MMBtu/hour	Boilers 4 and 5 became Acid Rain affected units under Phase I when they were used as substitution units for Unit 7. All four boilers are subject to Acid Rain Phase II.
005	Boiler Number 5 - 1,096.7 MMBtu/hour	
006	Boiler Number 6 - 3,704.8 MMBtu/hour	
007	Boiler Number 7 - 6,406.4 MMBtu/hour	

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

a. DEP Form 62-210.900(1)(a), dated 05/13/14.

b. DEP Form 62-210.900(1)(a)3, dated 06/24/16.

c. DEP Form 62-210.900(1)(a)1, dated 10/14/16 (for Calendar year 2017).

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

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

E.U. ID #	EPA ID	NO_X Limit
004	**ID No. 4 Boiler 4**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five NO_X emissions averaging plans for this unit. The plans are effective for calendar years **2017 - 2021**. Under the plans, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.52** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 311,012** MMBtu. See Specific Condition **A.4.**, below.
005	**ID No. 5 Boiler 5**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five NO_X emissions averaging plans for this unit. The plans are effective for calendar years **2017 - 2021**. Under the plans, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.60** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 300,422** MMBtu. See Specific Condition **A.4.**, below.
006	**ID No. 6 Boiler 6**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five NO_X emissions averaging plans for this unit. The plans are effective for calendar years **2017 - 2021**. Under the plans, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 6,067,693** MMBtu. See Specific Condition **A.4.**, below.

E.U. ID #	EPA ID	NO_X Limit
007	**ID No. 7 Boiler 7**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five NO_X emissions averaging plans for this unit. The plans are effective for calendar years **2017 - 2021**. Under the plans, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 25,775,190** MMBtu. See Specific Condition **A.4.**, below.

Also, see Additional Requirements a. and b, below.

Additional Requirements

a. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

b. In addition to the described NO_X compliance plan, these units shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

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

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

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

A.4. Comments, Notes, and Justifications. This Acid Rain Part contains a multi-state NO_X averaging plan established by Southern Company for calendar year 2017. [Rules 62-213.440, 62-214.330 & 62-214.420, F.A.C.]

Reporting Requirements

A.5. Demonstration of Compliance with the Phase II NO_X Averaging Plan. The Designated Representative shall provide a copy of the demonstration of compliance, prepared in accordance with 40 CFR 76.11(d), to the Department within 60 days after the end of the calendar year. [Rule 62-213.440, F.A.C.]

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Acid Rain Part Application

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

This submission is: ☐ New ☐ Revised ☒ Renewal

STEP 1

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

Plant name	State	ORIS/Plant Code
CRIST ELECTRIC GENERATING PLANT	**FL**	**641**

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

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

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

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
004		Yes		
005		Yes		
006		Yes		
007		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

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CRIST ELECTRIC GENERATING PLANT
Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

CRIST ELECTRIC GENERATING PLANT
Plant Name (from STEP 1)

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

Effect on Other Authorities.

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

STEP 4
For SO_2 Opt-in units only.

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

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

In column "h" enter the hours.

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

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CRIST ELECTRIC GENERATING PLANT
Plant Name (from STEP 1)

STEP 5

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

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

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

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

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

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

Signature	Date

STEP 7

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

Certification (for designated representative or alternate designated representative only)

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

Name **JAMES O. VICK**	Title **Director, Environmental Affairs**
Owner Company Name **Gulf Power Company**	
Phone **(850) 444- 6311**	E-mail address **jovick@southernco.com**
Signature James O Vick	Date 5/13/14

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Page 1

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

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

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

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Crist Electric Generating Plant Plant Name	FL State	641 ORIS Code
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# 004	ID# 005	ID# 006	ID# 007	ID#	ID#
	Type T	Type T	Type DBW	Type DBW	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☒	☒	☒	☒	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

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Crist Electric Generating Plant
Plant Name (from Step 1)

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STEP 2, cont'd.

	ID# 004	ID# 005	ID# 006	ID# 007	ID#	ID#
	Type T	Type T	Type DBW	Type DBW	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☒	☒	☒	☒	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

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

Standard Requirements

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

Special Provisions for Early Election Units

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

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

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

STEP 3, cont'd.

Certification

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

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

Name James O. Vick	
Signature James O Vick	Date 12/16/15

Contact Information

Email Address: jovick@southernco.com
Phone: (850) 444 - 6311

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Effective:03/11/2010

Florida Department of Environmental Protection

Phase II NO_x Averaging Plan

For more information, refer to 40 CFR 76.11

This submission is: ☐ New X Revised

STEP 1

Identify the units participating in this averaging plan by plant name, state, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan

Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7

$$\boxed{0.44} \leq \boxed{0.44}$$

$$\frac{\sum_{i=1}^{n} (R_{Li} \, x \, HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{li} \, x \, HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emissions limitation for unit i, in 16/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

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NO_X Averaging Plan - Page 2

Plant Name: **Southern Company Averaging Plan Participating Plants**

STEP 3

Mark one of the two options and enter dates.

X This plan is effective for calendar year 2017 through calendar year 2021 unless notification to terminate the plan is given.

☐ Treat this plan as identical plans, each effective for one calendar year for the following calendar years: ____, ____, ____, ____ and ____ unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

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

Name Larry S. Monroe	
Signature Larry S Monroe	Date 10/14/16

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Southern Company Averaging Plan Participating Plants
Plant Name (from Step 1) **as Listed in Step 1.**

Continue the identification of units from Step 1, page 1, here.

			(a)	(b)	(c)
Barry	AL	1	0.40	0.50	150,000
Barry	AL	2	0.40	0.50	150,000
Barry	AL	4	0.40	0.45	2,935,392
Barry	AL	5	0.40	0.45	29,234,375
Bowen	GA	1	0.45	0.42	37,184,471
Bowen	GA	2	0.45	0.43	33,735,559
Bowen	GA	3	0.45	0.43	39,424,486
Bowen	GA	4	0.45	0.43	55,660,598
Crist	FL	4	0.45	0.52	311,012
Crist	FL	5	0.45	0.60	300,422
Crist	FL	6	0.50	0.45	6,067,693
Crist	FL	7	0.50	0.45	25,775,190
Daniel	MS	1	0.45	0.33	14,416,070
Daniel	MS	2	0.45	0.33	16,472,125
Gadsden	AL	1	0.45	0.60	1,042,626
Gadsden	AL	2	0.45	0.60	841,608
Gaston	AL	1	0.50	0.52	346,132
Gaston	AL	2	0.50	0.52	417,022
Gaston	AL	3	0.50	0.52	546,930
Gaston	AL	4	0.50	0.52	270,558
Gaston	AL	5	0.45	0.48	33,297,386
Gorgas	AL	8	0.40	0.52	6,688,479
Gorgas	AL	9	0.40	0.52	5,635,034
Gorgas	AL	10	0.40	0.52	35,028,848
Greene Co	AL	1	0.68	0.60	1,741,402

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Southern Company Averaging Plan Participating Plants

Plant Name (from Step 1) **as Listed in Step 1.**

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	Emission Limitation	Alt. Contemp. Emission Limitation	Annual Heat Input Limit
Greene Co	AL	2	0.46	0.60	1,651,367
Hammond	GA	1	0.50	0.83	359,581
Hammond	GA	2	0.50	0.83	376,444
Hammond	GA	3	0.50	0.83	227,315
Hammond	GA	4	0.50	0.45	3,588,035
McIntosh	GA	1	0.50	0.86	77,555
Miller	AL	1	0.46	0.38	64,380,271
Miller	AL	2	0.46	0.38	62,064,460
Miller	AL	3	0.46	0.38	65,649,432
Miller	AL	4	0.46	0.38	65,726,718
Scherer	GA	1	0.40	0.50	51,872,189
Scherer	GA	2	0.40	0.50	40,460,144
Scherer	GA	3	0.45	0.50	48,799,518
Scherer	GA	4	0.40	0.50	48,799,518
Wansley	GA	1	0.45	0.41	35,570,651
Wansley	GA	2	0.45	0.42	30,211,340
Watson	MS	4	0.50	0.60	165,072
Watson	MS	5	0.50	0.60	488,052
Yates	GA	6	0.45	0.33	1,554,707
Yates	GA	7	0.45	0.30	412,079

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