Memorandum

Florida Department of Environmental Protection

I received 7-1-11

TO:	Jeff Koerner P.E., Program Administrator, Air Permitting and Compliance Section
THROUGH:	Jon Holtom, P.E., Section Administrator
FROM:	Kris Lanh, Engineer Specialist II
DATE:	June 15, 2011
SUBJECT:	Title V Air Operation Permit No. 0310045-030-AV

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park/Separations Technology, LLC Facility (NGS/SJRPP/ST)
Final Title V Air Operation Permit Revision

The final permit for this project is attached for your approval and signature.

The attached Final Determination identifies issuance of the draft/proposed Title V air operation permit, the final Title V air operation permit, and summarizes the publication process. There were no comments received from the applicant, public or EPA in response to the draft/proposed permit.

We recommend your approval of the attached final permit for this project.

Attachments

PERMITTEE

Jacksonville Electric Authority
4733 Heckscher Drive
Jacksonville, Florida 32226

PERMITTING AUTHORITY

Florida Department of Environmental Protection (Department)
Division of Air Resource Management
Bureau of Air Regulation, Title V Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Permit No. 0310045-030-AV
Northside Generating Station/St. Johns River Power Park/Separations Technology, LLC Facility (NGS/SJRPP/ST)

The purpose of this permitting project is for the revision of the existing Title V air operation permit for the above referenced facility to incorporate the provisions of air construction permit No. 0310045-026-AC, in particular specific condition No. 3 which requires the annual reporting of PSD pollutant emissions for a period of 5 years. The AC permit authorized the repair, replacement and maintenance of various equipment and components on the existing NGS Boiler No. 3 (EU003).

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Air Permit package on April 19, 2011. The applicant published the Public Notice of Intent to Issue Air Permit in the FLORIDA TIMES-UNION on April 29, 2011. The Department received the proof of publication on May 4, 2011. A proposed permit was issued for EPA review on May 4, 2011.

COMMENTS

No comments were received from the applicant or the EPA Region 4 office.

CONCLUSION

The final action of the Department is to issue the final permit without any changes.

NOTICE OF FINAL PERMIT

In the Matter of an Application for Permit by:

Jacksonville Electric Authority
4733 Heckscher Drive
Jacksonville, Florida 32226

Responsible Official:
James M. Chansler, P.E., D.P.A.
Chief Operations Officer

Permit No. 0310045-30-AV
Northside Generating Station/St. Johns River Power Park/Separations Technology, LLC Facility
Title V Air Operation Permit Revision
Duval County

Enclosed is the final permit package to revise the Title V air operation permit for Northside Generating Station/St. Johns River Power Park/Separations Technology, LLC Facility. The existing facility is located in Duval County at 4733 Heckscher Drive, Jacksonville, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes. Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Jeffery F. Koerner — 7-5-11

Jeffery F. Koerner, Program Administrator (Date)
Air Permitting and Compliance Section
Division of Air Resource Management

JFK/jh/kl

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit and Final Determination), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. James M. Chansler, P.E., D.P.A., Chief Operations Officer: chanjm@jea.com
Mr. Michael J. Brost, Vice President, Electric System: brosm@jea.com
Mr. N. Bert Gianazza, P.E., Environmental Sevices: GianNB@jea.com
Mr. Kennard F. Kosky, P.E., Golder Associate: ken.kosky@golder.com
Ms. Lori Tilley, Environmental Program Supervisor, City of Jacksonville: tilley@coj.net
Ms. Katy Forney, US EPA Region 4: forney.kathleen@epa.gov
Ms. Ana Oquendo, US EPA Region 4: oquendo.ana@epa.gov
Ms. Barbara Friday, DEP BAR: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Victoria Gibson, DEP BAR: victoria.gibson@dep.state.fl.us (for reading file)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

Lynn Scearce — July 5, 2011

(Clerk) (Date)

JEA
Northside Generating Station and St. Johns River Power Park (NGS/SJRPP)
Separations Technology, LLC (ST) Facility

Title V Air Operation Permit Revision
Permit No. 0310045-030-AV

APPLICANT

The applicant for this project is JEA. The applicant's responsible official and mailing address are: Mr. James M. Chansler, P.E., D.P.A., Chief Operating Officer, JEA, NGS/SJRPP/ST, 21 West Church Street, Jacksonville, Florida 32202.

FACILITY DESCRIPTION

The applicant operates the NGS/SJRPP/ST facility, which is located in Duval County at 4377 Heckscher Drive, Jacksonville.

The existing facility consists of the Northside Generating Station (NGS) and St. Johns River Power Park (SJRPP) facilities and the Separations Technology, LLC (ST) fly ash processing system.

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

PROJECT DESCRIPTION

The purpose of this permitting project is for the revision of the existing Title V air operation permit for the above referenced facility to incorporate the provisions of air construction permit No. 0310045-026-AC, in particular specific condition No. 3 which requires the annual reporting of PSD pollutant emissions for a period of 5 years. The AC permit authorized the repair, replacement and maintenance of various equipment and components on the existing NGS Boiler No. 3 (EU003).

PROCESSING SCHEDULE AND RELATED DOCUMENTS

Application for a Title V Air Operation Permit Revision received in hard copy on February 17, 2011.
Draft/Proposed Title V air operation permit revision issued on April 19, 2011.
Public Notice published April 29, 2011.

PRIMARY REGULATORY REQUIREMENTS

Title III: This facility is a major source of hazardous air pollutants (HAP), based on the Title V air operation permit renewal application received July 3, 2008.

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

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

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

NSPS: This facility operates units subject to the Standards of Performance for New Stationary Sources (NSPS) of 40 Code of Federal Regulations (CFR) 60.

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

Siting: Several of the emissions units were originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C.

CAM: Compliance Assurance Monitoring (CAM) applies to units at this facility. CAM applies to particulate matter emissions from the NGS Circulating Fluidized Bed Boiler Nos. 1 and 2 (Emission Unit ID Nos. -026 and -027) and SJRPP Boiler Nos. 1 and 2 (Emission Unit ID Nos. -016 and -017).

PROJECT REVIEW

The purpose of this Title V Air Operating Permit Revision is to incorporate the applicable specific conditions from previously issued air construction permit No. 0310045-026-AC. The AC permit authorized the permittee to conduct repairs, replacement and maintenance on various equipment and components related to Boiler No. 3 (EU003), including (but not limited to) the following:

- Electric generator rotor and assembly;
- Handcuff replacement on the primary superheater elements;
- Condenser structural assessment and repairs;
- Fiberglass circulating piping assessment and repairs;
- Feed water and heater drains piping flow corrosion inspection and repairs;
- Fuel oil piping condition assessment and repairs;
- Boiler soot-blowing system piping replacement;
- No. 4 feed water heater replacement;
- Furnace left and right water-wall replacement;
- Boiler waterside chemical cleaning;
- Replacement of Distributed Control System (DCS) and field devices;
- 480 Volt motor control center (MCC) refurbishment;
- Boiler duct work repair and replacement;
- Rebuild water rack;
- East air heater to wind-box expansion joint replacement;
- Induced draft fans A and B rotor replacements;
- Upgrade drum level transmitters;
- Closed cooling strainer cabinet replacement;
- Feed water heater and boiler feed water pump valve inspection and repair;
- Force draft fan motor replacement;
- Main steam line and cold reheat line elevation sag correction;
- Boiler feed pump turbine blade replacement; and
- Other changes as appropriate to ensure safe, reliable operations of the unit will be required.

Changes to the permit made as part of this revision are shown below:

1. A cross reference to the new reporting requirement was added to Specific Condition A.32.
2. To reflect the reporting requirements imposed by permit No. 0310045-026-AC, Specific Condition A.39. is added.

A.39. Actual Emissions Reporting. Based on analysis that compared baseline actual emissions with projected actual emissions and the project, and pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions:

a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.
b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded

submission of the report. The report shall contain the following:

(1) The name, address and telephone number of the owner or operator of the major stationary source;

(2) The annual emissions as calculated pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;

(3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and

(4) Any other information that the owner or operator wishes to include in the report.

c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

d. For this project, the permittee estimated the following baseline actual emissions: 243 tons/year of carbon monoxide (CO); 1,916 tons/year of nitrogen oxides (NO_X); 6,791 tons/year of sulfur dioxide (SO_2); 232 tons/year of particulate matter (PM); 232 tons/year particulate matter of 10 microns or less (PM_{10}); and 29 tons/year of volatile organic compounds (VOC).

e. The permittee shall compute and report annual emissions in accordance with Rule 62-210.370(2), F.A.C. as provided by Appendix C of this permit. For this project, the permittee shall use the following methods in reporting the actual annual emissions for Unit 3:

(1) The permittee shall use data collected from the continuous emissions monitoring systems (CEMS) to determine and report the actual annual emissions of SO_2 and NO_X.

(2) The permittee shall use the data collected from the required stack tests to determine and report the actual annual emissions of PM/PM_{10}. The permittee shall follow the stack test methods, test procedures and test frequencies specified in this permit.

(3) Unless otherwise approved by the Department, the permittee shall use the same emissions factors for reporting the actual annual emissions of CO and VOC as used in the application to establish baseline emissions.

(4) As defined in Rule 62-210.370(2), F.A.C., the permittee shall use a more accurate methodology if it becomes available.

[Permit No. 0310045-026-AC, Specific Condition, 3.A.3.]

3. Specific Condition **A.39** was renamed to **A.40.**

4. Appendix C, Common Conditions, was added to Section V of the permit.

CONCLUSION

This project revises Title V air operation permit No. 0310045-020-AV, which was effective January 1, 2009. This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statues (F.S.), and Chapters 62-4, 62-210, 62-212, 62-213 and 62-214, Florida Administrative Code, (F.A.C.).

Jacksonville Electric Authority

Northside Generating Station(NGS)/ St. Johns River Power Park (SJRPP)/ Separations Technology, LLC (ST) Facility

Facility ID No. 0310045
Duval County

Title V Air Operation Permit Revision

Permit No. 0310045-030-AV

(2nd Revision of Title V Air Operation Permit No. 0310045-020-AV)

DEPARTMENT OF ENVIRONMENTAL PROTECTION
FLORIDA

Permitting Authority:

State of Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Title V Section
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 717-9000, Fax: (850) 717-9097

Compliance Authority:

City of Jacksonville
Environmental and Compliance Department
Environmental Quality Division, Air Quality Branch

Jake Godbold City Hall Annex
407 North Laura Street, Third Floor
Jacksonville, Florida 32202

Telephone: (904) 255-7100, Fax: (904) 588-0518

Title V Air Operation Permit Revision
Permit No. 0310045-030-AV

Table of Contents

Section Page Number

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

PERMITTEE:
JEA
21 West Church Street
Jacksonville, Florida 32202

Permit No. 0310045-030-AV
NGS/SJRPP/ST Facility
Facility ID No. 0310045
Title V Air Operation Permit Revision

The purpose of this permit is for the revision of the Title V air operation permit for the above referenced facility to incorporate the monitoring requirements from permit No. 0310045-028-AC. The existing NGS/SJRPP/ST facility is located at 4377 Heckscher Drive, Jacksonville, in Duval County. UTM Coordinates are: Zone 17, 446.90 km East and 3359.150 km North. Latitude is: 30° 21' 52" North; and, Longitude is: 81° 37' 25" West.

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code, (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

0310045-020-AV Effective Date: January 1, 2009
0310045-028-AV Revision Effective Date: December 10, 2010
0310045-030-AV Revision Effective Date: June 23, 2011
Renewal Application Due Date: May 20, 2013
Expiration Date: December 31, 2013

Executed in Tallahassee, Florida
For the Division of Air Resource Management

Jeffery F. Koerner 7-5-11
(Signature) (Date)

Jeffery F. Koerner
(Printed Name of Above Designee)

Subsection A. Facility Description.

The Northside Generating Station (NGS) and St. Johns River Power Park (SJRPP) facilities and the Separations Technology, LLC (ST) facility are considered to be a single air emission "facility" for air permitting purposes.

NGS and SJRPP:

These operations consist of 5 boilers, NGS existing Boiler No. 3, which is a pre-NSPS boiler with a nominal rating of 564 MW and fired by natural gas, landfill gas, No. 6 residual fuel oil, and used oil; Boilers Nos. 1 and 2 and Auxiliary Boiler No. 1 have been permanently shutdown; NGS CFB Boilers Nos. 1 and 2, which are two coal, coal coated with latex, petroleum coke, and landfill gas fired circulating fluidized bed (CFB) boilers; SJRPP Boilers Nos. 1 and 2, which are two fossil fuel-fired steam generators (boilers) fired with pulverized coal, a blend of petroleum coke and coal, natural gas, new No. 2 distillate fuel oil (startup and low-load operation), and "on-specification" used oil; and, four pre-NSPS distillate fuel oil fired combustion turbines with a nominal rating of 52.5 MWs each, NGS Nos. 3, 4, 5 and 6. Emissions from the NGS Boiler No. 3 are uncontrolled. Emissions from the NGS CTs Nos. 3, 4, 5 and 6, are controlled by firing low sulfur fuel oil. Each NGS CFB boiler is equipped with a selective non-catalytic reduction (SNCR) system to reduce nitrogen oxides (NOx) emissions, limestone injection to reduce sulfur dioxide (SO_2) emissions, fabric filter to reduce particulate matter (PM and PM_{10}) emissions, while maximizing combustion efficiency and minimizing NOx formation to limit carbon monoxide (CO) and volatile organic compound (VOC) emissions. Emissions from the SJRPP Boilers Nos. 1 and 2 are controlled with an electrostatic precipitator, a limestone scrubber, and low-NOx burners. Permit No. 0310045-017-AC authorized the installation of selective catalytic reduction (SCR) systems and ammonia injection systems on the existing SJRPP Boiler Nos. 1 and 2; the Department did not require the installation of this equipment nor does the Department require its operation. The SJRPP and NGS facilities also include coal, petroleum coke, limestone and fly ash handling activities, of which various control devices, control strategies, and control techniques are required.

The material handling and storage operations will process ash, limestone, coal, coal coated with latex, and petroleum coke to support the operation of CFB Boilers Nos. 1 and 2. Each materials handling and storage operation will employ one or more control strategies to limit emissions of particulate matter to meet specific emission limitations and/or visible emissions limits. The control strategies include the use of best operating/design practices, total or partial enclosures, conditioned materials, wet suppression, water sprays, and dust collection systems.

ST:

ST has constructed, owns and operates a fly ash processing system on a portion of leased property at the JEA SJRPP facility in Duval County, Florida. The purpose of the equipment is to remove the residual carbon and ammonia from the JEA SJRPP fly ash leaving a saleable product. As a result, environmental benefits will include a 255,000 ton reduction in the fly ash currently sent to landfill by the JEA SJRPP each year and an overall reduction in the ammonia releases with the recovery and subsequent recycle of ammonia removed from the fly ash.

The fly ash processing system includes two fly ash receiving bins, a carbon separation unit, a clean-up vacuum, a fly ash surge bin, a mineral additive storage bin, and a gas-fired dryer. The particulate emissions generated from handling of the fly ash are collected from each source using pulse jet fabric filters. ST's triboelectric carbon separation technology partitions fly ash into mineral-rich and carbon-rich fractions. The mineral-rich fly ash can then be sold as a usable product. The carbon-rich fly ash is returned to the JEA SJRPP fly ash storage silos for eventual disposal at the onsite landfill.

The two-step beneficiation process consists of (1) removal of the residual carbon from the fly ash using ST's patented electrostatic separation technology, and (2) removal of residual ammonia from the fly ash using ST's ammonia removal technology (patent pending). In addition to residual carbon, the fly ash at the JEA SJRPP also contains trace amounts of ammonia that makes it unsuitable as a cement replacement. To solve this problem, ST installed an ammonia removal process. The recovered ammonia is subsequently returned to the JEA SJRPP for recycle.

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

Subsection B. Summary of Emissions Units.

E.U. No.	Brief Description
	Regulated Emissions Units
-003	NGS: Boiler No. 3
-006	NGS: Combustion Turbine No. 3
-007	NGS: Combustion Turbine No. 4
-008	NGS: Combustion Turbine No. 5
-009	NGS: Combustion Turbine No. 6
-016	SJRPP: Boiler No. 1
-017	SJRPP: Boiler No. 2
-022	SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations
-023	SJRPP: Fuel and Limestone Handling and Storage Operations
-024	SJRPP: Cooling Towers (2)
-026	NGS: Circulating Fluidized Bed Boiler No. 2
-027	NGS: Circulating Fluidized Bed Boiler No. 1
-028	NGS: Materials Handling and Storage Operations
-029	NGS: Crusher House/Building Baghouse Exhaust (DC1)
-031	NGS: Fuel Silos Dust Collectors (DC2 and DC3)
-033	NGS: Limestone Dryer/Mills Building
-034	NGS: Limestone Prep Building Dust Collectors
-035	NGS: Limestone Silos Bin Vent Filters
-036	NGS: Fly Ash Transport Blower Discharge
-037	NGS: Fly Ash Silos Bin Vents
-038	NGS: Bed Ash Silos Bin Vents
-042	NGS: AQCS Pebble Lime Silo Bin Vent
-044	ST: Separator A Filter - Receiver Vent
-045	ST: Separator B Filter - Receiver Vent
-046	ST: Separator Dust Collector Vent
-047	ST: Clean-up Vacuum Vent
-048	ST: Fly Ash Surge Bin Vent
-049	ST: Mineral Additive Storage Bin Vent
-050	ST: Gas-fired Dryer Stack
-051	NGS: Fly Ash Slurry Mix System Vents
-052	NGS: Bed Ash Slurry Mix System Vents
-053	NGS: Bed Ash Surge Hopper Bin Vents

E.U. No.	Brief Description
	Unregulated Emissions Units/Activities
The following Storage Tanks are located at the Northside Generating Station (NGS)	
-010	Bunker C Storage Tanks

-010	Storage Tank: 4,578,000 gallons - Bunker C
-010	Storage Tank: 4,578,000 gallons - Bunker C
-010	Storage Tank: 4,578,000 gallons - Bunker C
-010	Storage Tank: 11,256,000 gallons - Bunker C
-010	Storage Tank: 11,256,000 gallons - Bunker C
-010	Storage Tank: 11,256,000 gallons - Bunker C
-011	Diesel Storage Tanks
-011	Storage Tank #10: 168,000 gallons - Diesel
-011	Storage Tank #11: 4,200,000 gallons - Diesel
-011	Storage Tank #12: 4,200,000 gallons - Diesel
-012	Diesel Storage Tanks
-012	Storage Tank #13: 4,200,000 gallons - Diesel
-012	Storage Tank #14: 4,200,000 gallons - Diesel
-015	Waste Oil Storage Tanks
-015	Storage Tank: 750 gallons - Waste Oil Storage (Unit 1)
-015	Storage Tank: 1,000 gallons - Waste Oil Storage (Unit 2)
-015	Storage Tank: 575 gallons - Waste Oil Storage (Unit 3)
The following Storage Tanks are located at the St. Johns River Power Park (SJRPP)	
-019	Storage Tank: 636,106 gallons - Diesel
-020	Storage Tank: 10,069 gallons - Gasoline
-021	Storage Tank - Emergency Fire Pump: 1,123 gallons - Diesel
-021	Storage Tank - AQCS Emergency Generator Day Tank: 561 gallons - Diesel
-021	Storage Tank - Coal/Limestone Fuel Storage: 10,069 gallons - Diesel
-021	Storage Tank - Ash Landfill Fuel Storage: 10,069 gallons - Diesel
-021	Storage Tank - Power Block Emergency Generator Fuel Storage : 4,015 gallons - Diesel
-021	Storage Tank: 3,000 gallons - Diesel

Subsection C. Applicable Regulations.

Based on the Title V Air Operation Renewal application received July 3, 2008, this facility is a major source of hazardous air pollutants (HAP). This facility is classified as a PSD major facility. A summary of important applicable regulations is shown in the following table.

Regulation	E.U. ID No(s).
Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input	-003
Rule 62-296.702, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter: Fossil Fuel Steam Generators	-003
Acid Rain, Phase II	-003
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)	-003
Rule 62-210.300, F.A.C., Permits Required	-006, -007, -008 & -009
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)	-006, -007, -008 & -009
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-016 & -017
NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978	-016 & -017

Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-016 & -017
Acid Rain, Phase II and Phase I	-016 & -017
Compliance Assurance Monitoring (CAM)	-016 & -017
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)	-016 & -017
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-023
NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants	-023
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-023
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-022
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-024
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-026 & -027
NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978	-026 & -027
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-026 & -027
Acid Rain, Phase II and Phase I	-026 & -027
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)	-026 & -027
Compliance Assurance Monitoring (CAM)	-026 & -027
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-029 & -031
NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants (coal handling at NGS, excluding open storage piles)	-029 & -031
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-033, -034 & -035
Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants (limestone handling at NGS, except for open storage piles and truck unloading)	-033, -034 & -035
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	See Subsection III.H.
Rule 62-296.711, F.A.C., Reasonable Available Control Technology (RACT) - Materials Handling, Sizing, Screening, Crushing and Grinding Operations	See Subsection III.H.
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-044 - -050
Rule 62-296.711, F.A.C., Reasonable Available Control Technology - Materials Handling, Sizing, Screening, Crushing and Grinding Operations	-044 - -050
Rule 62-296.712, F.A.C., Reasonable Available Control Technology (RACT) - Miscellaneous Manufacturing Process Operations	-044 - -050

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

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

Emissions and Controls

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

FW2.1. Not federally enforceable. Odor Nuisance. Pursuant to City of Jacksonville Ordinance Code (JOC) Chapter 376, any facility that causes or contributes to the emission of objectionable odors which results in the City of Jacksonville Environmental Resource Management Department's (ERMD) Environmental Quality Division (EQD) receiving and validating complaints from five (5) or more different households within a 90 day period and can be cited for objectionable odors. [JOC Chapter 376]

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)(a), F.A.C.; and, Part X, Rule 2.1001, JEPB]

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)1., F.A.C.; and, Part X, Rule 2.1001, JEPB]

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: chemical or water application to unpaved roads or unpaved yard areas; paving and maintenance of roads, parking areas and plant grounds; landscaping and planting of vegetation; regular mowing of grass and care of vegetation; limiting access to plant property by unnecessary vehicles; storage of bagged chemical products in weather-tight buildings (except for fertilizer); prompt cleanup of spilled powdered chemical products; confining abrasive blasting where possible; and other techniques, as necessary. Also, for the solid waste disposal area, wetting agents shall be applied as needed. [Rule 62-296.320(4)(c), F.A.C.; PSD-FL-010 and PA 81-13; and, 0310045-003-AC/PSD-FL-265; and, proposed by applicant in Title V air operation permit renewal application received July 3, 2008.]

Annual Reports and Fees

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

FW6. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by May 1, 2009 and April 1st of each year, thereafter. [Rule 62-210.370(3), F.A.C.]

FW7. Annual Emissions Fee Form and Fee. The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download 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/permitting/tvfee.htm. [Rule 62-213.205, F.A.C.]

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

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

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.
d. Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to: Department of Community Affairs, Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9921, Fax: (850) 488-1739.
e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 1515, Lanham-Seabrook, MD 20703-1515, Telephone: (301) 429-5018.

Any required reports to be sent to the National Response Center, should be sent to: National Response Center, EPA Office of Solid Waste and Emergency Response, USEPA (5305 W), 401 M Street SW, Washington, D.C. 20460, Telephone: (800) 424-8802.
Send the required annual registration fee using approved forms made payable to: Cashier, Department of Community Affairs, State Emergency Response Commission, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2149
[Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

FW10. Clean Air Interstate Rule (CAIR) Applicable Units. This facility contains emissions units that are subject to CAIR. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia recommended vacatur of the Clean Air Interstate Rule. Because of this decision, the applicable CAIR requirements that were identified in the renewal application are not being included in the permit at this time. If, and at such time that, CAIR is ultimately upheld, you must begin complying with the CAIR program requirements contained in the renewal application and the Title V permit must be revised accordingly. [Rules 62-213.440 and 62-296.470, F.A.C.]

Subsection A. Emissions Unit -003

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

E.U. ID No.	Brief Description
-003	NGS Boiler No. 3

NGS Boiler No. 3 is a fossil fuel-fired steam generator with a nominal nameplate rating of 563.7 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, liquefied petroleum (LP) gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 5033 MMBtu per hour when firing fuel oil; (2) 5260 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 5033 - 5260 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a stack of 300 feet. NGS Boiler No. 3 began commercial operation in 1977.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; Rule 62-296.702, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter: Fossil Fuel Steam Generators; AC16-85951; 0310045-012-AC; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

A.1. Permitted Capacity. The maximum operation heat input rates, based on the higher heating value (HHV) of the fuel, are as follows:

E.U. ID No.	MMBtu/hr Heat Input (HHV)	Fuel Type
-003	5260	Natural Gas
	5260	Landfill Gas
	5033	New No. 6 Fuel Oil
	5033	"On-specification" Used Oil
	5033-5260	Fuel Oil and Natural Gas
	5033-5260	Fuel Oil and Natural/Landfill Gases

Note: When a blend of fuel oil and natural and/or landfill gas is fired, the heat input is prorated based on the percent heat input of each fuel. [Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)); and 62-296.405(1), F.A.C.]

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

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

A.3. Methods of Operation - Fuels. The only fuels allowed to be burned are natural gas, LP gas, landfill gas, new No. 6 fuel oil, "on-specification" used oil, and a blend of fuel oil and natural gas and/or landfill gas. "On-specification" used oil containing any quantifiable levels of polychlorinated biphenyls (PCB) can only be fired when the emissions unit is at normal operating temperatures. LP gas is used as the igniter fuel when natural gas is not available. [Rule 62-213.410, F.A.C.; 40 CFR 271.20(e)(3); AC16-85951; BACT; applicant request dated June 14, 1996; and, 0310045-012-AC]

A.4. Hours of Operation. This emissions unit may operate continuously (8760 hours/year). [Rule 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions Nos. **A.5.** thru **A.9.**, and **A.11.**, are based on the specified averaging time of the applicable test method.

A.5. Visible Emissions. For Boiler No. 3, visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions limit shall compliance test for visible emissions annually and as otherwise required by Chapter 62-297, F.A.C. [Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.6. Visible Emissions – Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. [Rule 62-210.700(3), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. [Rules 62-296.405(1)(b) and 62-296.702(2)(a), F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.8. Particulate Matter - Soot Blowing and Load Change. 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, Part III, Rule 2.301, JEPB]

A.9. Sulfur Dioxide. SO_2 emissions shall not exceed 1.98 pounds per million Btu heat input, as measured by applicable compliance methods. Any calculations or methods used to demonstrate compliance shall be based on the total heat input from all fossil fuels, including natural gas, and the sulfur from all fuels fired. [Rules 62-213.440 and 62-296.405(1)(c)1.a., F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.10. Sulfur Dioxide - Sulfur Content. For Boiler No. 3, the sulfur content of the as-fired No. 6 fuel oil shall not exceed 1.8 percent, by weight, if the SO_2 continuous emissions monitor system is temporarily inoperative. [Rule 62-296.405(1)(e)3., F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.11. Nitrogen Oxides (expressed as NO_2). For Boiler No. 3, nitrogen oxides shall not exceed 0.30 lb/MMBtu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1)(d)1., F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.12. On-Specification 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 Limitations.* This emissions unit is permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 parts 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 the JEA in the production and distribution of electricity, not to exceed 1,000,000 gallons during any calendar year.
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 Requirements.* 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:
(1) 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)]
(2) 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.
(a) 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.
(b) 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.
(c) 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).

f. *Recordkeeping Requirements.* 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.
   (2) Results of the analyses of each deposit of used oil, as required by the above conditions.
   (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.

[Rule 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

Excess Emissions

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

A.13. Excess Emissions From Malfunctions. Excess emissions resulting from malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) 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.; and, Part III, Rule 2.301, JEPB]

A.14. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in Appendix Q Protocol for Startup and Shutdown. [Rule 62-210.700(1), F.A.C. and Proposed by the Applicant in the Renewal Application]

A.15. Excess Emissions From Startup and Shut Down. Excess emissions from existing fossil fuel steam generators 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.; and, Part III, Rule 2.301, JEPB]

A.16. 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.; and, Part III, Rule 2.301, JEPB]

Continuous Emissions Monitoring Requirements

A.17. Sulfur Dioxide.

a. For Boiler No. 3, the permittee elected to monitor emissions using a SO_2 continuous emissions monitoring system (CEMS).
b. The CEMS shall be calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and

demonstrated based on a 24-hour daily average. A Relative Accuracy Testing Audit (RATA) shall be performed no less than annually.

c. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that can be used is that which was last used to demonstrate compliance prior to the loss of the CEMS, **or** the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 1.8%, by weight, or less.

d. In the event of natural gas disruption and the emissions units have to fire 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 1.8%, by weight, or less.

[Rules 62-213.440, 62-204.800, 62-296.405(1)(c)3., and 62-296.405(1)(f)1.b., F.A.C.]

A.18. Nitrogen Oxides. For Boiler No. 3, compliance with the nitrogen oxides (expressed as NO_2) limit of 0.30 lb/MMBtu shall be demonstrated by the following:

a. Through the use of a CEMS installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 60, Appendix F, and 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and demonstrated based on a 30-day rolling average.

b. The performance specifications, location of the monitor, data requirements, data reduction and reporting requirements shall conform with the requirements of 40 CFR 51, Appendix P, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and 40 CFR 60, Appendix B, adopted by reference in Rule 62-204.800, F.A.C.

[Rules 62-296.405(1)(e)4. and 62-296.405(1)(f), F.A.C.; Part X, Rule 2.1001, JEPB; and, 40 CFR 60 & 75]

Test Methods and Procedures

A.19. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B, or 5F	Methods for Determining Particulate Matter Emissions
EPA Method 19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
DEP Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

A.20. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions and particulate matter emissions. [Rule 62-297.310(7), F.A.C.]

A.21. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, SO_2 and NO_X. The SO_2 and NO_X RATA test data may be used to demonstrate compliance with the test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7)(a)3., F.A.C.]

A.22. 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.23. Visible Emissions.

a. For Boiler No. 3, the test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.

b. The visible emissions test(s) required shall be conducted simultaneously with particulate matter testing and soot blowing and non-soot blowing operating modes.

c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rule 62-296.405(1)(e)1. & 5., F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.24. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

a. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

b. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

   (1) For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

   (2) For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value. [Rule 62-297.401, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.25. Particulate Matter.

a. The test methods for particulate 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 with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 (with Orsat analysis) or 3A shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.

b. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-213.440, 62-296.405(1)(e)2. & 5., and 62-297.401, F.A.C.; Part X, Rule 2.1001, JEPB; and, Part XI, Rule 2.1101, JEPB]

A.26. 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.

a. For Boiler No. 3, the permittee shall demonstrate compliance with the 1.98 lbs/MMBtu heat input standard by either using the above referenced EPA test methods, including if used during a RATA for the SO_2 CEMS, or, as an alternate sampling procedure authorized by permit, a sulfur analyses of the as-fired fuel oils and gaseous fuels while compliance testing for particulate matter and visible emissions.
b. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
c. For monitoring purposes and in lieu of fuel sampling and analysis, the permittee shall operate an SO_2 CEMs. A RATA shall be conducted at least annually in accordance with 40 CFR 75.

[Rules 62-213.440, 62-296.405(1)(e)3. & 5., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.; Part V, Rule 2.501, JEPB; Part X, Rule 2.1001, JEPB; and, Part XI, Rule 2.1101, JEPB]

A.27. Fuel Sampling and Analysis. For Boiler No. 3, the following fuel sampling and analysis protocol shall be used if the permittee opts to demonstrate compliance with the sulfur dioxide standard using an alternate sampling procedure authorized by permit and conducted while performing a compliance test for particulate matter and visible emissions:

a. Determine and record the as-fired fuel sulfur content, percent by weight, (1) for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel oil following each fuel delivery, (2) for gaseous fuels using ASTM D 1072-80, or the latest edition (the permittee can default to the maximum sulfur content guaranteed by the supplier).
b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the ratio of fuel oil to gas if co-fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.
c. The analyses of the No. 6 fuel oil, as received from the supplier, shall include the following:
   (1) Density (ASTM D 1298-80 or the latest edition).
   (2) Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).
d. The analyses of the gaseous fuels, as received from the supplier, shall include the following:
   (1) Density (ASTM D1137-53, ASTM D1945-64, or the latest edition).
   (2)Calorific heat value in Btu per cubic foot (ASTM D1137-53, ASTM D1945-64, ASTM D1826-77, or the latest edition).
e. Utilize the above information in a., b., c. and d. to calculate the SO_2 emission rate.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; and, 40 CFR 60. Appendix A]

A.28. Operating Conditions During Testing - Particulate Matter and Visible Emissions. Compliance tests for particulate matter and visible emissions during soot blowing and steady-state (non-soot blowing) operations shall be conducted at least once, annually, if liquid fuel is fired for more than 400 hours. All visible emissions tests shall be conducted concurrently with the particulate matter emissions tests. Testing shall be conducted as follows:

a. *100% Fuel Oil Firing*. Particulate matter and visible emissions tests during soot blowing and steady-state operations shall be performed on each emissions unit while firing fuel oil containing a sulfur content equal to or less than 1.8%, by weight, except that such test shall not be required to be performed during any federal fiscal year that testing is performed in accordance with Specific Condition **A.28.b**.
b. *Co-firing Fuel Oil with Gases*. If fuel oil containing a sulfur content greater than 1.8%, by weight, is co-fired with gases (i.e., natural gas, landfill gas, LP gas), then particulate matter and visible emissions tests during soot blowing and steady-state operations shall be performed as soon as practicable, but in no event more than 60 days from the day of first firing the higher percent sulfur fuel oil, while co-firing such fuel

oil with the proportion of gas required to maintain SO_2 emissions between 90 to 100% of the SO_2 emissions limitation (1.62 to 1.98 lbs/MMBtu heat input, respectively). Following successful completion of such particulate matter and visible emissions testing, further particulate matter and visible emissions testing shall not be required during the remaining federal fiscal year unless fuel oil is fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests. If fuel oil is co-fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests for particulate matter and visible emissions, then additional particulate matter and visible emissions tests shall be performed as described above and as soon as practicable, but in no event more than 60 days from the day of first firing the higher sulfur percent fuel oil. Following successful completion of such particulate matter and visible emissions testing, further particulate matter and visible emissions testing shall not be required during the remaining federal fiscal year unless fuel oil is fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests. If any additional particulate matter and visible emissions tests are imposed after completion of any required annual compliance tests, then the frequency testing base date shall be reset to 12-months after the date of completion of the last tests.

[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.29. Annual VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.30. Annual And Renewal PM Testing. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; Part XI, Rule 2.1101, JEPB; and, ASP Number 97-B-01.]

A.31. Used Oil Sampling. Compliance with the "on-specification" used oil requirements will be determined from a sample collected from each batch delivered for firing. [Rules 62-4.070 and 62-213.440; and, 40 CFR 279]

Recordkeeping and Reporting Requirements

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

A.32. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions	Every 3 months (quarter)	**A.33. & A.34.**
Actual Emissions Reporting	Annually	**A.39.**

[Rule 62-296.405(1)(g), F.A.C.]

A.33. Notification of Excess Emissions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.34. Excess Emissions Reports. For each calendar quarter, submit to the ERMD-EQD a written report of emissions in excess of emission limiting standards, as set forth in Rule 62-296.405(1), F.A.C., and any continuous emissions monitoring system outages. The nature and cause of the excess emissions shall be explained. The report shall be submitted within 30 calendar days following the last day of the quarterly period. 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.; and, Part X, Rule 2.1001, JEPB]

A.35. Used Oil Records. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. [Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.36. Used Oil Annual Report. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Boiler No. 3 during the calendar year. [Rule 62-213.440(1)(b)2.b., F.A.C.]

A.37. Shut Down Records. When the NGS boiler No. 3 is shut down, it shall be recorded in the boiler's operating log book. [Rule 62-213.440, F.A.C.; and, AC16-85951]

A.38. Fuel Consumption Records. The owner or operator shall create and maintain for each emissions unit hourly records of the amount of each fuel fired, the ratio of fuel oil to gas if co-fired, and the heating value and sulfur content, percent by weight, of each fuel fired. These records must be of sufficient detail to be able to identify when additional particulate matter and visible emissions testing is required pursuant to specific condition **A.29.b.**, and, when applicable, demonstrate compliance with the requirements of Specific Condition **A.27.e**. [Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

A.39. Actual Emissions Reporting. Based on analysis that compared baseline actual emissions with projected actual emissions, and the project, and pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions:

a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.

b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:

(1) The name, address and telephone number of the owner or operator of the major stationary source;

(2) The annual emissions as calculated pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;

(3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and
(4) Any other information that the owner or operator wishes to include in the report.

c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

d. For this project, the permittee estimated the following baseline actual emissions: 243 tons/year of carbon monoxide (CO); 1,916 tons/year of nitrogen oxides (NO_X); 6,791 tons/year of sulfur dioxide (SO_2); 232 tons/year of particulate matter (PM), 232 tons/year particulate matter of 10 microns or less (PM_{10}); and 29 tons/year of volatile organic compounds (VOC).

e. The permittee shall compute and report annual emissions in accordance with Rule 62-210.370(2), F.A.C. as provided by Appendix C of this permit. For this project, the permittee shall use the following methods in reporting the actual annual emissions for Unit 3:
(1) The permittee shall use data collected from the CEMS to determine and report the actual annual emissions of SO_2 and NO_X.
(2) The permittee shall use the data collected from the required stack tests to determine and report the actual annual emissions of PM/PM_{10}. The permittee shall follow the stack test methods, test procedures and test frequencies specified in the current Title V air operation permit.
(3) Unless otherwise approved by the Department, the permittee shall use the same emissions factors for reporting the actual annual emissions of CO and VOC as used in the application to establish baseline emissions.
(4) As defined in Rule 62-210.370(2), F.A.C., the permittee shall use a more accurate methodology if it becomes available.

[Permit No. 0310045-026-AC, Specific Condition, 3.A.3.]

Miscellaneous

A.40. Operation and Maintenance Plan. For Boiler No. 3, an Operation and Maintenance Plan required under RACT for PM is attached and a part of this permit pursuant to Rule 62-296.700(6), F.A.C. All activities shall be performed as scheduled and recorded data made available to the ERMD-EQD upon request. Records shall be maintained on file for a minimum of five (5) years. Appendix O&M, Operation and Maintenance Plan under RACT for PM, is attached as part of this permit. [Rule 62-296.700(6), F.A.C.; and, Part X, Rule 2.1001, JEPB]

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

E.U. ID No.	Brief Description
-006	NGS: Combustion Turbine No. 3
-007	NGS: Combustion Turbine No. 4
-008	NGS: Combustion Turbine No. 5
-009	NGS: Combustion Turbine No. 6

Emission unit numbers -006, -007, -008 and -009 are combustion turbines (CTs) manufactured by General Electric (Model MS 7000) and are designated as CTs No. 3, No. 4, No. 5 and No. 6, respectively. Each CT has a maximum heat input from new No. 2 distillate fuel oil of 901.0 MMBtu (LHV: lower heating value). The No. 2 fuel oil has a maximum sulfur content of 0.5%, by weight. These CTs are used as peaking units during peak demand times, during emergencies, and during controls testing, to run a nominal 56.2 MW generator (each). Emissions from the CTs are uncontrolled. Direct water spray fogger devices were installed in the inlet ducts of each CT to provide adiabatic inlet air cooling that increases turbine output and decreases heat rate. A group of exhaust stacks serve the CTs. CT No. 3 began commercial service in February 1975, No. 4 in January 1975, No. 5 in February 1974, and, No. 6 in December 1974.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR). These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rates, based on the lower heating value (LHV) of the fuel, are as follows:

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
-006	901.0 (LHV)	New No. 2 Fuel Oil
-007	901.0 (LHV)	New No. 2 Fuel Oil
-008	901.0 (LHV)	New No. 2 Fuel Oil
-009	901.0 (LHV)	New No. 2 Fuel Oil

The attached Appendix NGS: CT Heat Input Nominal Values is a chart of the Base Load MW vs. Temperature to aid in defining full load for visible emissions testing purposes, since the manufacturer's curves are not available. The heat input numbers are only nominal values. An estimated heat input rate can be calculated from fuel records showing the quantity and the heat content of the fuel fired, and shall be provided upon request. [Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)).]

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

B.3. Methods of Operation - Fuels. Only new No. 2 distillate fuel oil shall be fired in the combustion turbines. [Rule 62-213.410, F.A.C.]

B.4. Hours of Operation.

a. These CTs may operate continuously, i.e., 8,760 hours/year.
b. Each CT shall not exceed 399 hrs/yr operation while using foggers.

[Rules 62-4.160(2) and 62-210.200(Definitions - PTE), F.A.C.; and, 0310045-006-AC]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition No. **B.5.** is based on the specified averaging time of the applicable test method.

B.5. Visible Emissions. Visible emissions from each combustion turbine shall not be equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]

B.6. Sulfur Dioxide - Sulfur Content. The sulfur content of the new No. 2 distillate fuel oil shall not exceed 0.5 percent, by weight. [Requested in Title V permit application.]

Excess Emissions

B.7. Excess Emissions Allowed. Excess emissions from these emissions units 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. [Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

B.8. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in Appendix Q Protocol for Startup and Shutdown. [Rule 62-210.700(1), F.A.C. and Proposed by the Applicant in the Renewal Application]

B.9. 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.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

B.10. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis for each fuel delivery. [Rule 62-213.440, F.A.C.]

Test Methods and Procedures

B.11. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition	Methods for Evaluating Fuel Sulfur Content
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department.
[Chapter 62-297, F.A.C.]

B.12. Visible Emissions Testing - Biennial. By this permit, biennial (odd years) emissions compliance testing for visible emissions is required for each emissions unit, but is not required for those emissions units burning No. 2 fuel oil for less than 400 hours during the previous even year or the current odd year in question. [Rules 62-297.310(7)(a)4. & 8., F.A.C.; Part XI, Rule 2.1101, JEPB.]

B.13. 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.14. VE Test Method. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference 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.; and, Part XI, Rule 2.1101, JEPB]

B.15. Fuel Sulfur Analysis. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition. [Rules 62-213.440 and 62-297.440, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.16. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

The attached Appendix NGS: CT Heat Input Nominal Values is a chart of the Base Load MW vs. Temperature to aid in defining full load for visible emissions testing purposes, since the manufacturer's curves are not available. The heat input numbers are only nominal values.

[Rules 62-297.310(2), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

Recordkeeping and Reporting Requirements

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

B.17. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**B.18.**

[Rule 62-210.700(6), F.A.C.]

B.18. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

B.19. Test Reports.

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the ERMD-EQD on the results of each such test.
b. The required test report shall be filed with the ERMD-EQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.20. Fuel Records. Records of No. 2 fuel oil consumption shall be maintained and made available to the ERMD-EQD upon request. [Rule 62-213.440, F.A.C.]

B.21. Foggers. A log book shall be maintained to show when each CT is using a fogger device and shall provide the beginning and ending times (hour and minute) of its use. [Rule 62-4.070(3), F.A.C.]

Subsection C. Emissions Units -016 & -017

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

E.U. ID No.	Brief Description
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

SJRPP Boilers Nos. 1 and 2 are fossil fuel-fired steam generators, each having a nominal nameplate rating of 679.6 megawatts (electric). These emissions units are allowed to fire pulverized coal, a blend of petroleum coke and coal, natural gas, new No. 2 distillate fuel oil (startup and low-load operation), and "on-specification" used oil. The maximum heat input to each emissions unit is 6,144 million Btu per hour. SJRPP Boilers Nos. 1 and 2 are dry bottom wall-fired boilers and use an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulfurization (FGD) unit to control sulfur dioxide, low NO_X burners and over-fire air to control nitrogen oxides, and good combustion to control carbon monoxide.

SCR and Ammonia Injection Systems

Permit No. 0310045-017-AC authorized the installation of Selective Catalytic Reduction (SCR) systems on SJRPP Boiler Nos. 1 and 2. The permittee elected to install these controls as part of its plan to comply with the Clean Air Interstate Rule (Rule 62-296.470(CAIR), F.A.C.). When operating, the SCR systems decrease nitrogen oxides (NOx) emissions from the SJRPP Boiler Nos. 1 and 2, which allows the plant to meet annual and ozone season NOx CAIR allocations.

Installation of the SCR systems resulted in collateral increases in emissions of sulfuric acid mist (SAM) and particulate matter (PM/PM_{10}). The potential increase of SAM emissions is a result of the oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) that is emitted as SAM after the flue gas desulfurization (FGD) system. Permit No. 0310045-017-AC required the installation of additional ammonia injection systems on SJRPP Boiler Nos. 1 and 2 to reduce SAM emissions. Ammonia is injected downstream of the SCR reactor and upstream of the existing electrostatic precipitator (ESP). The ammonia reacts with SO_3 to form salts (e.g., ammonium sulfate), which are collected in the ESP. With the additional ammonia injection systems, there shall be no PSD-significant emissions increases due to the installation of SCR systems on SJRPP Boiler Nos. 1 and 2. Under this project, there were no other planned changes in SJRPP Boiler Nos. 1 and 2.

The SCR system/ammonia injection system on SJRPP Boiler No. 1 became operational on July 16, 2009 and the SCR system/ammonia injection system on SJRPP Boiler No. 2 became operational on March 24, 2009.

Each boiler exhausts through its own stack (640 feet above grade). The stack diameter is 22.3 feet, exit temperature is 156 degrees F and the actual stack gas flow rate is 1,800,000 acfm. SJRPP Boiler No. 1 began commercial operation in December 1986. SJRPP Boiler No. 2 began commercial operation in March 1988.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase II and Phase I; NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(8)(b)2., F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration [PSD; PSD-FL-010; PSD-FL-010, amendment dated 10/28/1986; PSD-FL-010(A, B, C & D); 0310045-012-AC/PSD-FL-010E; and, 0310045-014-AC/PSD-FL-010F]; Siting's PA 81-13: Conditions of Certification; PA 81-13L; Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981; and, Compliance Assurance Monitoring (CAM), adopted and incorporated in Rule 62-204.800, F.A.C.; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

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

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum operation heat input rates are as follows:

E.U. ID No.	MMBtu/hr Heat Input
-016	6,144
-017	6,144

[Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)); PSD-FL-010; Part III, Rule 2.301, JEPB; and, PA 81-13]

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

C.3. Methods of Operation.

a. The only fuels allowed to be fired are coal, a coal blend with a maximum of 30 percent petroleum coke (by weight), new No. 2 distillate fuel oil, and "on-specification" used oil.
b. The new No. 2 fuel oil shall be used for startup and low load operation.
c. The maximum weight of petroleum coke burned shall not exceed 150,000 pounds per hour, based on a 30-day rolling average using production information for the amount of coal and petcoke metered from the coal storage bins to the boilers.
d. "On-specification" used oil will be generally fired as a blend with the No. 2 fuel oil. "On-specification" used oil containing PCBs above the detectable level of 2 ppm shall not be used for startup or shutdown. "On-specification" used oil containing PCBs between 2 and 49 ppm can only be fired when the emissions unit is at normal operating temperatures.
e. Either coal, a blend of coal and petroleum coke, or fuel oil shall not be fired in the emissions units unless both electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 CFR 60, Subpart Da.
f. No fraction of the flue gas shall be allowed to bypass the limestone flue gas desulfurization (FGD) system to reheat the gasses exiting from the FGD system, if the bypass will cause overall SO_2 removal efficiency less than 90 percent or as otherwise provided in 40 CFR 60, Subpart Da. The percentage and amount of flue gas bypassing the FGD system shall be documented.
g. If at any time the permittee determines that it is appropriate to use supplemental fuel during periods of startup, shutdown, flame stabilization and low load operation, then No. 2 fuel oil and/or natural gas shall be used for the pulverized coal and petroleum coke-fired Boiler No. 1 or Boiler No. 2. [1]
h. Natural Gas Firing[2]: The permittee is authorized to continuously fire natural gas in SJRPP Boiler No. 1 and 2 during normal operations. For each unit, there are 28 natural gas burners rated at 25 MMBtu/hour per burner. The maximum total heat input to each unit from firing natural gas is 700 MMBtu/hour. {Permitting Note: Natural gas firing shall only achieve approximately 11% of full load operation. Other authorized fuels shall be co-fired with natural gas to achieve full load operation.}

[Rule 62-213.410, F.A.C.; PSD-FL-010; 0310045-014-AC/PSD-FL-010F; PA 81-13L&M; PSD-FL-010(A & B); 40 CFR 761.20(e); [1]0310045-024-AC/PSD-FL-010H; [2]0310045-029-AC/PSD-FL-010I; and, requested by the applicant in the Title V permit application.]

C.4. Hours of Operation. These emissions units are allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.; Part III, Rule 2.301, JEPB; PSD-FL-010; and, PA 81-13]

Air Pollution Control Technologies and Measures

C.5. SCR Systems. The permittee shall tune, operate and maintain new SCR systems for SJRPP Boiler Nos. 1 and 2 to reduce emissions of NOx. In general, the SCR systems include the following equipment: ammonia storage; ammonia flow control unit (AFCU); ammonia injection grid (AIG); vanadium pentoxide catalyst; an SCR reactor chamber; an SCR bypass system; and other ancillary equipment. [Rules 62-296.470(CAIR) and 62-210.200(PTE), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.2.]

C.6. Ammonia Injection Systems. The permittee shall tune, operate and maintain new ammonia injection systems on SJRPP Boiler Nos. 1 and 2 to mitigate the formation of SAM due to the increased oxidation of SO_2 to SO_3 across the new SCR reactors. Ammonia is injected downstream of the SCR reactor and upstream of the existing ESP. The control system regulating the amount of ammonia injected to control SAM is integrated into the plant digital control system. The ammonia reacts with SO_3 to form salts (e.g., ammonium sulfate), which are collected in the ESP. With the additional ammonia injection systems, there shall be no PSD-significant emissions increases due to the installation of SCR systems on SJRPP Boiler Nos. 1 and 2. The proposed equipment includes storage tanks, piping, injectors, a control system and other ancillary equipment. The ammonia injection systems shall be operable when the SCR system is initially available for service. [Rule 62-212.400(12), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.3.]

C.7. Circumvention - SCR and Ammonia Injection Systems. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. Operation of the SCR is not required. As necessary, the permittee shall operate the ammonia injection system for SAM emissions control to ensure the project does not result in a PSD-significant emissions increase (7 tons/year) of sulfuric acid mist emissions above baseline actual emissions (1,317 tons/year). [Rules 62-210.650 and 62-212.400(12), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.4.]

C.8. Ammonia Slip. Ammonia slip measured at the stack downstream of all emission control systems shall not exceed 5 parts per million by volume (ppmv). Annual testing of ammonia shall be conducted and corrective measures taken if measured values exceed 2 ppmv. [Rule 62-4.070(3), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.7.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions Nos. **C.9., C.10., C.13.** thru **C.16.,** and **C.18.** thru **C.20.,** are based on the specified averaging time of the applicable test method.

C.9. Appendix SJRPP: Table 6 (Revised) - Part C, SJRPP, is incorporated by reference (attached) for SJRPP Boilers 1 and 2 (EU-016 and EU-017, respectively). [PSD-FL-010, amendment dated October 28, 1986; and, PSD-FL-010C, clerked July 29, 1999.]

C.10. Particulate Matter. No owner or operator shall cause to be discharged into the atmosphere from any emissions unit any gases which contain particulate matter in excess of:

a. 0.03 lb/million Btu heat input derived from the combustion of solid or liquid fuels (coal, a blend of coal and petroleum coke, or fuel oil) and 184 lb/hour[1];
b. 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel (coal or a blend of coal and petroleum coke), and
c. 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

d. Particulate matter emissions shall be controlled with an electrostatic precipitator.

[40 CFR 60.42a(a)(1), (2) & (3); PSD-FL-010 and BACT; PA 81-13; PSD-FL-010(A & B); and, [1]PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part A.]

C.11. Ash Content.

a. The maximum ash content of the coal is 18%, by weight.
b. The maximum ash content of the No. 2 fuel oil is 0.01%, by weight.
[PSD-FL-010; and, PA 81-13]

C.12. Visible Emissions. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6 minute average), except for one 6-minute period per hour of not more than 27 percent opacity. [40 CFR 60.42a(b); PA 81-13; and, PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part A.]

C.13. Sulfur Dioxide - Coal Only. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel any gases which contain sulfur dioxide in excess of:

a. 1.20 lb/million Btu heat input, maximum two-hour average, and 0.76 lb/MMBtu heat input (90% reduction of the potential combustion concentration), 30-day rolling average and 4,669 lb/hour[1]; or
b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 0.60 lb/million Btu heat input.
c. 100 percent of the potential combustion concentration (zero percent reduction), when emissions are less than 0.20 lb/million Btu heat input.
d. SO_2 emissions shall be controlled with a lime/limestone flue gas desulfurization system on each boiler.

[40 CFR 60.43a(a)(1), (2) & (3); PSD-FL-010 and BACT; PA 81-13); and, [1]PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part A.]

C.14. Sulfur Dioxide - Coal and Petroleum Coke Blends.

a. When coals with a sulfur content up to or equal to 2%, by weight, are co-fired with petroleum coke, the SO_2 emissions shall not exceed 0.53 lb/MMBtu heat input and a minimum of 79% reduction shall be achieved in the flue gas desulfurization system.
b. When coals with a sulfur content between 2 and 3.63%, by weight, are co-fired with petroleum coke, the SO_2 emission limitation shall be based on the following formula:

   SO_2 emission limit (lb/MMBtu) = (0.2 x C/100) + 0.4
   where: C = percent of coal co-fired on a heat input basis.
   Please note that C is on a heat input basis and not on a weight input basis, so appropriate conversions should be used.

c. When coals with a sulfur content greater than 3.63%, by weight, are co-fired with petroleum coke, the SO_2 emissions shall not exceed the following formula:

   SO_2 (lb/MMBtu) = (0.1653 x C x S – 0.4 x C + 40) x 1/100
   where: C = percent of coal co-fired on a heat input basis; and,
   S = weight percent sulfur in coal.

d. The maximum SO_2 emission rate when co-firing petroleum coke and coal shall not exceed 0.676 lb/MMBtu heat input.
e. Compliance with the SO_2 emissions limit shall be based on a 30-day rolling average for those days when petroleum coke is fired. Any use of petroleum coke during a 24-hour period shall be considered 1 day of the 30-day rolling average. The 30-day rolling average shall be calculated according to the Standards of Performance for New Stationary Sources (NSPS) codified in 40 CFR 60, Subpart Da, except as noted above.

[PSD-FL-010; PSD-FL-010(A & B); 0310045-014-AC/PSD-FL-010F; and, PA 81-13L]

C.15. Sulfur Dioxide - Liquid Fuel Only. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility which combusts liquid fuel any gases which contain sulfur dioxide in excess of:

a. 340 ng/J (0.80 lb/million Btu) heat input and 90 percent reduction, or
b. 100 percent of the potential combustion concentration (zero percent reduction), when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

[40 CFR 60.43a(b)(1) & (2)]

C.16. Sulfur Dioxide. Compliance with the emission limitation and percent reduction requirements are both determined on a 30-day rolling average basis. [40 CFR 60.43a(g); PSD-FL-010; and, PA 81-13]

C.17. Sulfur Dioxide - Sulfur Content.

a. The maximum coal sulfur content shall not exceed 4.0 percent, by weight.
b. The maximum sulfur content of the petroleum coke - coal blend shall not exceed 4 percent, by weight.
c. The maximum sulfur content of the No. 2 fuel oil is 0.76%, by weight.

[PSD-FL-010; PA 81-13; PSD-FL-010(A & B); 0310045-014-AC/PSD-FL-010F; and, PA 81-13L]

C.18. Sulfur Dioxide. When fuel oil and coal (or a blend of coal and petroleum coke) are combusted simultaneously, the applicable standard is determined by proration using the following formulas:

a. If emissions of SO_2 to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input:
   $PS_{SO2} = (340X + 520Y)/100$ and
   $\%P_S = 10$
b. If emissions of SO_2 to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:
   $PS_{SO2} = (340X + 520Y)/100$ and
   $\%P_S = (10X + 30Y)/100$
   where:
   PS_{SO2} = the prorated standard for sulfur dioxide when combusting fuel oil and coal (or a blend of coal and petroleum coke) simultaneously (ng/J heat input).
   $\%P_S$ = percentage of potential SO_2 emissions allowed.
   X = the percentage of total heat input derived from the combustion of fuel oil (excluding solid-derived fuels).
   Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke (including solid-derived fuels).

[40 CFR 60.43a(h)(1) & (2)]

C.19.1. Nitrogen Oxides. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

a. NOx emissions limits.
   (1) Coal or coal-petroleum coke blend: 0.60 lb/million Btu (260 ng/J) heat input and 3,686 lb/hour[1];
   (2) Fuel oil: 130 ng/J (0.30 lb/million Btu) heat input.
b. NOx reduction requirement.
   (1) Solid fuels: 65 percent reduction of potential combustion concentration;
   (2) Liquid fuels: 30 percent reduction of potential combustion concentration.

[40 CFR 60.44a(a)(1) & (2); and, [1]PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part A.]

C.19.2. Nitrogen Oxides (NOx). No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility (emissions unit) any gases that contain NOx (expressed as NO_2) in excess of the following emission limit, based on a 30-day rolling average basis, and NOx reduction requirement:

(1) 0.20 lb/million Btu [40 CFR 60.44Da(a)(1)], and

(2) 25 percent reduction [40 CFR 60.44Da(a)(2)]. Compliance with the NOx emission limitation under 40 CFR 60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2). [40 CFR 60.48Da(b)]

[0310045-029-AC/PSD-FL-010I]

C.20.1. Nitrogen Oxides. When fuel oil and coal (or a blend of coal and petroleum coke) are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$PS_{NOX} = (130X + 260Y)/100$

where:

PS_{NOX} is the prorated standard for nitrogen oxides when combusting coal (or a blend of coal and petroleum coke) and fuel oil simultaneously (ng/J heat input).

X = the percentage of total heat input derived from the combustion of fuel oil.

Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke.

[40 CFR 60.44a(c); and, PSD-FL-010]

C.20.2. Nitrogen Oxides (NOx). When two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_{NOX} = (0.20w + 0.30x + 0.60z)/100$

Where:

E_{NOX} = Applicable standard for NO_X when multiple fuels are combusted simultaneously (lb/MMBtu of heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the standard of 0.20 lb/MMBtu of heat input for authorized gaseous fuels;

x = Percentage of total heat input derived from the combustion of fuels subject to the standard of 0.30 lb/MMBtu of heat input for authorized liquid fuels;

z = Percentage of total heat input derived from the combustion of fuels subject to the standard of 0.60 lb/MMBtu of heat input for authorized bituminous coal or a blend of bituminous coal with petcoke. [40 CFR 60.44Da(c)]

[0310045-029-AC/PSD-FL-010I]

C.21. On-Specification 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 Limitations.* This emissions unit is permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 parts 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 the JEA in the production and distribution of electricity, not to exceed 1,000,000 gallons during any calendar year.

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 Requirements.* 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:

(1) 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)]

(2) 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.

(a) 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.

(b) 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.

(c) 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).

f. *Recordkeeping Requirements.* 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.
   (2) Results of the analyses of each deposit of used oil, as required by the above conditions.
   (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 Requirement.* 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.

[Rule 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

Excess Emissions

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

C.22. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) 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. See Appendix Q: Protocol for Startup and Shutdown.

Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in Appendix Q Protocol for Startup and Shutdown. [Rule 62-210.700(1), F.A.C. and Proposed by the Applicant in the Renewal Application]

[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

C.23. 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.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

C.24. Compliance Assurance Monitoring (CAM) Requirements. The emissions units are subject to the CAM requirements contained in the attached Appendix CAM: SJRPP Boilers Nos. 1 and 2. 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(7)(b), F.A.C. [40 CFR 64; and, Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Compliance Provisions

C.25. Compliance with PM. Compliance with the particulate matter emission limitation under 40 CFR 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under 40 CFR 60.42a(a)(2) and (3). [40 CFR 60.46a(a)]

C.26. Compliance With NO_X. Compliance with the nitrogen oxides emission limitation under 40 CFR 60.44a(a)(1) constitutes compliance with the percent reduction requirements under 40 CFR 60.44a(a)(2). [40 CFR 60.46a(b)]

C.27. NSPS Excess Emissions. The particulate matter emission standards under 40 CFR 60.42a and the nitrogen oxide standards under 40 CFR 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under 40 CFR 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under 40 CFR 60.46a(d) are implemented. [40 CFR 60.46a(c)]

C.28. NSPS Excess Emissions During Emergency Conditions. During emergency conditions in the principle company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

a. Operating all operable flue gas desulfurization modules, and bringing back into operation any malfunctioned module as soon as repairs are completed.
b. Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation.

[40 CFR 60.46a(d)(1) & (2)]

C.29. Compliance Averages. Compliance with the sulfur dioxide emission limitations and the percentage reduction requirements under 40 CFR 60.43a and the nitrogen oxides emissions limitations under 40 CFR 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards. [40 CFR 60.46a(e)]

C.30. Compliance Determinations. Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (NO_X only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emissions rates for the 30 successive boiler operating days. [40 CFR 60.46a(g)]

C.31. Insufficient Data. If the owner or operator has not obtained the minimum quantity of emission data as required under 40 CFR 60.47a, compliance of the affected facility with the emission requirements under 40 CFR 60.43a and 60.44a for the day on which the 30-day period ends may be determined by the Administrator following the applicable procedures in section 7 of Method 19. [40 CFR 60.46a(h)]

Continuous Monitoring Requirements

C.32. Opacity. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharges to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator). [40 CFR 60.47a(a)]

C.33. Sulfur Dioxide. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows: Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device. [40 CFR 60.47a(b)(1)]

C.34. Nitrogen Oxides. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere. [40 CFR 60.47a(c)]

C.35. O_2 and CO_2. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored. [40 CFR 60.47a(d)]

C.36. Requirement to Operate CEMS. The continuous monitoring systems are operated and data recorded during all periods of operation at the affected facility including periods of startup, shutdown, malfunction, or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. [40 CFR 60.47a(e)]

C.37. Minimum Data Requirement. The owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR 60.47a(h). [40 CFR 60.47a(f)]

C.38. One-hour Averages. The 1-hour averages required under 40 CFR 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under 40 CFR 60.46a. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b). At least two data points must be used to calculate the 1-hour averages. [40 CFR 60.47a(g)]

C.39. Supplemental Data. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in 40 CFR 60.47a(f), the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods are given in 40 CFR 60.47a(j).

a. Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.
b. Method 7 shall be used to determine the NOx concentration at the same location as the NO_X monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.
c. The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.
d. The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million Btu) heat input.

[40 CFR 60.47a(h)(1), (2), (3) & (4)]

C.40. Monitoring System Performance Evaluations. The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d). Acceptable alternative methods and procedures are given in 40 CFR 60.47a(j).

a. Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_X concentrations.
b. SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of 40 CFR 60.
c. For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides firing solid fuel is 1,000 ppm.
d. For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

[40 CFR 60.47a(i)(1), (2), (3), & (5)]

C.41. Reference Method Alternatives. The owner or operator may use the following as alternatives to the reference methods and procedures specified in 40 CFR 60.47a.

a. For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under 40 CFR 60.47a(i), the conditions under 40 CFR 60.46(d)(1) apply; these conditions do not apply under 40 CFR 60.47a(h).
b. For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time is 1 hour.
c. For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.
d. For Method 3B, Method 3A may be used.

[40 CFR 60.47a(j)]

Test Methods and Procedures

C.42. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B, or 5F	Methods for Determining Particulate Matter Emissions
EPA Methods 6, 6A, 6B, or 6C	Methods for Determining Sulfur Dioxide Emissions
EPA Method 7, Method 7A, 7C, 7D, or 7E	Determination of Nitrogen Oxide Emissions
EPA Method 8 or EPA Conditional Test Method (CTM-013)[1]	Determination of Sulfuric Acid Mist Emissions CTM-013 may be used in lieu of EPA Method 8
EPA Method 19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
EPA Method 9	Visual Determination of the Opacity of Emissions
EPA Conditional Test Method	Determination of Ammonia Emissions (used to demonstrate

Method(s)	Description of Method(s) and Comment(s)
(CTM-027), or EPA Method 320	compliance with the ammonia slip limit)[2]

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C; [1]DEP Order No. 09-I-AP, issued 06/22/09; and, [2]Permit No. 0310045-017-AC, specific condition 3.11.]

C.43. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1[st] to September 30[th]), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for particulate matter, nitrogen oxides, sulfur dioxide, and visible emissions. The NO_X and SO_2 RATA test data may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.; and, PA 81-13]

C.44. Annual Tests - Ammonia Injection for SAM Emissions Control and SAM Emission Rates. During each federal fiscal year, the permittee shall conduct performance tests to determine the SAM emission rates and adjust the ammonia injection rates as necessary. At least six representative 1-hour test runs shall be conducted on either SJRPP Boiler Nos. 1 and 2. Annual performance tests shall be alternated between the boilers such that testing is conducted on a boiler at least twice during each 5-year period. Within 45 days following the last test run conducted, the permittee shall provide a report summarizing the emissions tests conducted, the results of the tests, the catalyst oxidation rate, how the automated control system was adjusted, and the updated algorithm used for the automated control system or the updated series of related performance curves. [Rules 62-4.070(3) and 62-212.300(1)(e), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.9.]

C.45. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, SO_2 and NO_X. [Rule 62-297.310(7)(a)3., F.A.C.]

C.46. 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.]

C.47. Required Test Methods. In conducting performance tests, the owner or operator shall use as reference methods and procedures the methods in Appendix A of 40 CFR 60 or the methods and procedures as specified in 40 CFR 60.48a, except as provided in 40 CFR 60.8(b). 40 CFR 60.8(f) does not apply to this section for SO_2 and NOx. Acceptable alternative methods are given in 40 CFR 60.48a(e). [40 CFR 60.48a(a)]

C.48. Particulate Matter. The owner or operator shall determine compliance with the particulate matter standard as follows:

a. The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.
b. For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.
   (1) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).
   (2) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same transverse points as, the particulate run. If the

particulate run has more than 12 transverse points, the O_2 transverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 transverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each transverse point.

c. Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

[40 CFR 60.48a(b)(1), (2) & (3)]

C.49. Sulfur Dioxide. The owner or operator shall determine compliance with the sulfur dioxide standards as follows:

a. The percent of potential SO_2 emissions ($\%P_S$) to the atmosphere shall be computed using the following equation:

$\%P_S = [(100 - \%R_F)(100 - \%R_S)]/100$

where:

$\%P_S$ = percent of potential SO_2 emissions, percent.
$\%R_F$ = percent reduction from fuel pretreatment, percent.
$\%R_S$ = percent reduction by SO_2 control system, percent.

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

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

d. The appropriate procedures in Method 19 shall be used to determine the emission rate.

e. The continuous monitoring system in 40 CFR 60.47a(b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

[40 CFR 60.48a(c)(1), (2), (3), (4) & (5)]

C.50. Nitrogen Oxides. The owner or operator shall determine compliance with the NO_X standard as follows:

a. The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_X.

b. The continuous monitoring system in 40 CFR 60.47a(c) and (d) shall be used to determine the concentrations of NO_X and CO_2 or O_2.

[40 CFR 60.48a(d)(1) & (2)]

C.51. Alternative Test Methods. The owner or operator may use the following as alternatives to the reference methods and procedures specified in 40 CFR 60.48a:

a. For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed the average temperature of 160 °C (320 °F). Procedures 2.1 and 2.3 of Method 5B in 40 CFR 60, Appendix A may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

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

[40 CFR 60.48a(e)(1) & (2)]

C.52. Used Oil Compliance Requirements. Compliance with the "on-specification" used oil requirements will be determined as follows:

a. Analysis of a sample collected from each batch delivered for firing; or,
b. The new batch delivery is from a collection site that has an acceptable analysis already on file with the facility and the analytical results are assumed by the facility for the batch.
c. For quantification purposes, the highest concentration of each constituent as determined by any analysis is assumed to be the concentration of the constituent of the blended used oil.

[Rules 62-4.070 and 62-213.440(1)(b)2.b., F.A.C.; Part V, Rule 2.501, JEPB; and, 40 CFR 279]

C.53. If the permittee wants the CEMs RATA tests for SO_2 and NO_X to be considered as formal compliance tests, then the permittee must satisfy all of the requirements (i.e., prior notification, submittal requirements, etc.) of Rule 62-297.310, F.A.C. [Rules 62-297.310(7) and 62-213.440, F.A.C.]

Recordkeeping and Reporting Requirements

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

C.54. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**C.73.**
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**C.64.**
Stack monitoring, fuel usage and fuel analysis data	Every 3 months (quarter)	**C.69.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

C.55. Performance Test Data. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator. [40 CFR 60.49a(a)]

C.56. SO_2 and NO_X Reporting. For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

a. Calendar date.
b. The average sulfur dioxide and nitrogen oxides emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standards; and, description of corrective actions taken.
c. Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.
d. Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and, description of corrective actions taken.
e. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_X only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data other than startup, shutdown, malfunction, or emergency conditions.
f. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

g. Identification of the times when hourly averages have been obtained based on manual sampling methods.
h. Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
i. Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

[40 CFR 60.49a(b)(1), (2), (3), (4), (5), (6), (7), (8) & (9)]

C.57. Additional Reporting Requirements. If the required quantity of emission data as required by 40 CFR 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR 60.46a(h) is reported to the Administrator for that 30-day period:

a. The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.
b. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.
c. The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.
d. The applicable potential combustion concentration.
e. The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

[40 CFR 60.49a(c)(1), (2), (3), (4) & (5)]

C.58. Control System Malfunction Notification. If any standards under 40 CFR 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

a. Indicating if emergency conditions existed and requirements under 40 CFR 60.46a(d) were met during each period, and
b. Listing the following information:
   (1) Time periods the emergency condition existed;
   (2) Electrical output and demand on the owner or operator's electric utility system and the affected facility;
   (3) Amount of power purchased from interconnected neighboring utility companies during the emergency period;
   (4) Percent reduction in emissions achieved;
   (5) Atmospheric emission rate (ng/J) of the pollutant discharged; and
   (6) Actions taken to correct control system malfunction.

[40 CFR 60.49a(d)(1) & (2)]

C.59. Fuel Pretreatment Credit. If fuel pretreatment credit toward the sulfur dioxide emission standard under 40 CFR 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

a. Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of 40 CFR 60.48a and Method 19 (appendix A); and
b. Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

[40 CFR 60.49a(e)(1) & (2)]

C.60. Missing CEMS Data. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability.

Operations of the control system and the affected facility during periods of data unavailability are to be compared with operation of the control system and the affected facility before and following the period of data unavailability. [40 CFR 60.49a(f)]

C.61. CEMS and Compliance Notification. The owner or operator of the affected facility shall submit a signed statement indicating whether:

a. The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.
b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.
c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
d. Compliance with the standards has or has not been achieved during the reporting period.

[40 CFR 60.49a(g)(1), (2), (3) & (4)]

C.62. Opacity Excess Emissions Reports. For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter. [40 CFR 60.49a(h)]

C.63. Quarterly Report Submission. The owner or operator of an affected facility shall submit the written reports required under 40 CFR 60.49(a) and 40 CFR 60, Subpart A, to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. [40 CFR 60.49a(i)]

C.64. Quarterly Excess Emissions Reports. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

C.65. Used Oil Records. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units; or, hourly if fired unblended. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. [Rule 62-213.440(1)(b)2.b., F.A.C.; Part V, Rule 2.501, JEPB; and, 40 CFR 279.61 and 761.20(e)]

C.66. Used Oil Reporting. The permittee shall include in the "Annual Operating Report (AOR) for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Boilers Nos. 1 and 2 and the auxiliary boilers during the calendar year. [Rule 62-213.440(1)(b)2.b., F.A.C.; and, Part V, Rule 2.501, JEPB]

C.67.1. Fuel Consumption Records. The owner or operator shall maintain, for each emissions unit, a daily log of the amounts and types of fuels fired and copies of fuel analyses containing information on the sulfur and ash content, percent by weight, and heating values. [Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010 and PA 81-13]

C.67.2. Natural Gas Firing Records. The permittee shall maintain sufficient records to document the firing of natural gas. [Permit No. 0310045-029-AC/PSD-FL-010I]

C.68. Reporting and Recordkeeping.

a. Documentation verifying that the coal and petroleum coke fuel blends combusted in Boilers Nos. 1 and 2 have not exceeded the 30 percent maximum petroleum coke by weight limit shall be maintained and made available upon request by the Department or the ERMD-EQD. [Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; 0310045-014-AC/PSD-FL-010F; and, PA81-13L]

b. The permittee shall maintain and submit to the Department and ERMD-EQD on an annual basis for a period of five years from the date the emissions unit is co-fired with petroleum coke above 20%, by weight, information demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational changes did not result in emissions increases of nitrogen oxides, carbon monoxide, sulfur dioxide, sulfuric acid mist, volatile organic compounds, and particulate matter. [0310045-014-AC/PSD-FL-010F; and, PA81-13L]

C.69. Reporting and Recordkeeping. Stack monitoring, fuel usage and fuel analysis data shall be reported to the ERMD-EQD on a quarterly basis in accordance with 40 CFR 60.7. [PA81-13]

C.70. Operational Data - SCR and Ammonia Injection Systems. For each unit, the permittee shall continuously monitor and record the ammonia injection rate for SAM emissions control and the hours of SCR bypass. [Rule 62-4.070(3), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.13.]

C.71. Test Reports - SCR and Ammonia Injection Systems. For each sulfuric acid mist test run, the test report shall indicate the ammonia injection rate for SAM emissions control, unit load, unit heat input rate, and total secondary power input to the electrostatic precipitator. [Rule 62-297.310(8), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.12.]

Miscellaneous

C.72. Stack Height. The height of each boiler's exhaust stack for SJRPP Boiler No. 1 and No. 2 shall not be less than 640 feet above grade. [PSD-FL-010 and PA81-13]

C.73. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

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

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

C.74. NSPS Requirements - Subpart Da. Except as otherwise provided in this permit, the combustion turbine shall comply with all applicable provisions of 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(8)(b)2., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.47a. These emissions units shall comply with **Appendix 40 CFR 60 Subpart Da** included with this permit. [Rule 62-204.800(8)(b)2., F.A.C.]

C.75. Reference Method Alternatives. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified: The emission rate (E) of particulate matter, SO_2 and NOx may be determined by using the Fc factor, provided that the following procedure is used:

a. The emission rate (E) shall be computed using the following equation:
$E = C\ F_c\ (100 / \%\ CO_2)$
where:
E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
% CO_2 = carbon dioxide concentration, percent dry basis.
F_c = factor as determined in appropriate sections of Method 19.

b. If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b)(2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209\ (F_{da} / F_{ca})$, then the following procedure shall be followed:

(1) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(2) When F_o is less than 0.97 F_{oa} and when the average difference ($\bar{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(3) When F_o is greater than 1.03 F_{oa} and when $\bar{d}$ is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

[40 CFR 60.46(d)(1)]

Source Obligation - SCR and Ammonia Injection Systems

C.76. Source Obligation - SCR and Ammonia Injection Systems. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by increasing its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction has not yet commenced on the source or modification. [Rule 62-212.400(12)(c), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 2.1.]

C.77. Annual PM/PM_{10} and SAM Emissions Projections - SCR and Ammonia Injection Systems. For the project under Permit No. 0310045-017-AC, the permittee projected that actual annual emissions due to the project would not exceed the PM/PM_{10} annual emissions (322 + 14 = 336 tons/year); and would not exceed the SAM annual emissions (1,317 + 6 = 1,323 tons/year). The permittee shall demonstrate this by compiling and submitting the reports required by this permit. For the purposes of this reporting, all PM emissions are considered to be PM_{10} emissions. [Rules 62-212.300 and 62-210.370, F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.5.]

C.78. Ammonia Injection for SAM Emissions Control - SCR and Ammonia Injection Systems. On an annual basis, the permittee must demonstrate that SAM emissions as a result of the project under Permit No. 0310045-017-AC do not exceed 1,323 tons per year. The permittee shall install and operate the ammonia injection system at a frequency and injection rate for SAM control to satisfy this requirement. An automated control system is used to adjust the ammonia flow rate for the given set of operating conditions based on the most recent performance test results. [Rules 62-4.070(3) and 62-212.300(1)(e), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.6.]

C.79. Annual PM/PM_{10} and SAM Emissions Reports - SCR and Ammonia Injection Systems. In accordance with Rule 62-212.300(1)(e), F.A.C., the permittee shall comply with the following monitoring, reporting and recordkeeping provisions:

a. The permittee shall monitor the PM/PM_{10} and SAM emissions using the most reliable information available. On a calendar year basis, the permittee shall calculate and maintain a record of the annual emissions (tons per year) for a period of 5 years after completing construction on each unit's control system *{Permitting note: The control system on SJRPP Boiler No. 1 became operational on July 16, 2009 and the control system on SJRPP Boiler No. 2 became operational on March 24, 2009, therefore, the 5-year period for both boilers is effective for calendar year (CY) 2010 emissions through CY 2014 emissions}*. Emissions shall be computed in accordance with Rule 62-210.370, F.A.C.

b. Within 60 days after each calendar year following completion of construction on each new control system, the permittee shall report to the Compliance Authority the annual emissions for each unit for the preceding calendar year. The report shall contain the following:
    a. Name, address and telephone number of the owner or operator of the major stationary source;
    b. Annual emissions as calculated pursuant to subparagraph 62-212.300(1)(e)1., F.A.C.;
    c. If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and
    d. Any other information that the owner or operator wishes to include in the report.

c. The information required to be documented and maintained shall be submitted to the Compliance Authority, where it will be available for review to the general public.

[Rule 62-212.300(1)(e), F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.14.]

C.80. PM/PM_{10} and SAM Emissions Computation and Reporting - SCR and Ammonia Injection Systems. The permittee shall compute PM/PM_{10} and SAM emissions in accordance with the following requirements.

a. For each year of reporting required, emissions shall be computed based on the controlled and uncontrolled emissions factors determined during the required annual emissions test. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.
b. With appropriate supporting test data, multiple emission factors may be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.
c. The permittee shall compute emissions by multiplying the appropriate controlled or uncontrolled emission factor by the annual heat input rate for the period over which the emissions are computed. The uncontrolled emissions factor shall be used if the minimum ammonia injection rate established for the latest test is not met.
d. The permittee shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the Department or Compliance Authority for any regulatory purpose.

[Rule 62-210.370, F.A.C.; and, Permit No. 0310045-017-AC, specific condition 3.15.]

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

E.U. ID No.	Brief Description
-023	SJRPP: Fuel and Limestone Handling and Storage Operations

-023a	Rotary Railcar Dumper Building
-023b	Conveyor C-3 Tunnel Ventilation (6,400 cfm)
-023b	Conveyor C-3 Tunnel Ventilation (6,400 cfm)
-023b	Conveyor C-3 Tunnel Ventilation (21,600 cfm)
-023c	Shiphold Operations
-023d	Ship Unloader Hopper and Spillage Collector Transfers
-023d	Ship Unloader Hopper to Transfer CT-1, Spillage Conveyor
-023e	Fuel Transfer Building (DC-2)
-023e	Transfer Stations Nos. 1 thru 7
-023e	Transfer Point 9GC-04 to 9GC-05
-023f	Stacker/Reclaimer (Stacker Mode)
-023f	Stacker
-023f	Reclaimer
-023g	Emergency Reclaim Hoppers - Load Out
-023j	Limestone Truck Loadout & Transfer
-023k	Limestone Storage Pile #1 - Existing
-023k	Limestone Storage Pile #2 - Fuel Yard
-023k	Limestone Loadout
-023k	Coal Pile
-023k	Petroleum Coke Pile
-023l	Limestone Reclaim Hopper with Fabric Filter (3DC-01)
-023l	Limestone Silos with Fabric Filters (2: 1DC-01 and 2DC-01)
-023l	Quick Lime Silo with Fabric Filter (used for water treatment)
-023l	Fuel Handling Building with Fabric Filter (DC-3)
-023l	Unit #1 Fuel Storage Bins with Fabric Filter (DC-4)
-023l	Unit #2 Fuel Storage Bins with Fabric Filter (DC-5)

The coal receiving, storage and transfer systems at the coal and petroleum coke storage yard support the operation of the two power boilers. Fugitive particulate matter emissions are generated from limestone handling and storage systems. The emissions units/points are as depicted in Table 6 (Revised) – Part B, SJRPP: Materials Handling and Storage Operations [PSD-FL-010, and as amended (was originally Tables 2 and 6)]. Particulate matter emissions and visible emissions are controlled using fabric filter systems, water sprays, wetting agents, and full enclosures or partial enclosures, covers and wind screens, where appropriate and required by permit. Visible emissions limits shall be used for compliance purposes.

{Permitting notes: This emissions unit/points are regulated under NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants, adopted and incorporated by reference in Rule 62-204.800(8)(b)31., F.A.C.; Rule 62-212.400(5), F.A.C., Prevention of Significant Deterioration (PSD) New Source Review: PSD-FL-010, and as amended (A) thru (E); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated 07/07/1981; PPSA: PA 81-13, and as amended; and, 0310045-015-AC/PSD-FL-010(G).}

Essential Potential to Emit (PTE) Parameters

D.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010]

D.2. Air Quality Control Systems (AQCS). The permittee shall maintain and continue to use the AQCS established in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations, to minimize particulate matter emissions. [Rules 62-4.070(3) and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended October 28, 1986; PSD-FL-010C, clerked July 29, 1999; 0310045-012-AC/PSD-FL-010E; and, 0310045-015-AC/PSD-FL-010G]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Condition Nos. **D.3.** and **D.4.** are based on the specified averaging time of the applicable test method.

D.3. The emissions unit/points are subject to the included Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations. [PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended 10/28/1986; PSD-FL-010C, clerked July 29, 1999; 0310045-012-AC/PSD-FL-010E; and, 0310045-015-AC/PSD-FL-010G]

D.4. Visible Emissions. Visible emissions (VE) shall be used for compliance purposes and shall not exceed the following opacity limits as established in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations:

E.U. ID No.	Brief Description	VE Limit (% opacity)
-023	SJRPP: Fuel and Limestone Handling and Storage Operations	
-023a	Rotary Railcar Dumper Building	10
-023b	Conveyor C-3 Tunnel Ventilation (6,400 cfm)	5
-023b	Conveyor C-3 Tunnel Ventilation (6,400 cfm)	5
-023b	Conveyor C-3 Tunnel Ventilation (21,600 cfm)	5
-023c	Shiphold Operations	10
-023d	Ship Unloader Hopper and Spillage Collector Transfers	10
-023d	Ship Unloader Hopper to Transfer CT-1, Spillage Conveyor	10
-023e	Fuel Transfer Building (DC-2)	10

-023e	Transfer Stations Nos. 1 thru 7	5
-023e	Transfer Point 9GC-04 to 9GC-05	5
-023f	Stacker/Reclaimer (Stacker Mode)	10
-023f	Stacker	10
-023f	Reclaimer	10
-023g	Emergency Reclaim Hoppers - Load Out	10
-023j	Limestone Truck Loadout & Transfer	10
-023k	Limestone Storage Pile #1 - Existing	10
-023k	Limestone Storage Pile #2 - Fuel Yard	10
-023k	Limestone Loadout	10
-023k	Coal Pile	10
-023k	Petroleum Coke Pile	10
-023l	Limestone Reclaim Hopper with Fabric Filter (3DC-01)	5
-023l	Limestone Silos with Fabric Filters (2: 1DC-01 and 2DC-01)	5
-023l	Quick Lime Silo with Fabric Filter (used for water treatment)	5
-023l	Fuel Handling Building with Fabric Filter (DC-3)	5
-023l	Unit #1 Fuel Storage Bins with Fabric Filter (DC-4)	5
-023l	Unit #2 Fuel Storage Bins with Fabric Filter (DC-5)	5

[PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended October 28, 1986; PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part B; 0310045-012-AC/PSD-FL-010E; and, 0310045-015-AC/PSD-FL-010G]

Excess Emissions

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

D.5. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) 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.; and, Part III, Rule 2.301, JEPB]

D.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. [Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Test Methods and Procedures

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

Method(s)	Description of Method(s) and Comment(s)

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department.
[Chapter 62-297, F.A.C.]

D.8. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), the following emissions units/points shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions:

E.U. ID No.	Brief Description
-0231	Limestone Reclaim Hopper with Fabric Filter (3DC-01)
-0231	Limestone Silos with Fabric Filters (2: 1DC-01 and 2DC-01)
-0231	Fuel Handling Building with Fabric Filter (DC-3)
-0231	Unit #1 Fuel Storage Bins with Fabric Filter (DC-4)
-0231	Unit #2 Fuel Storage Bins with Fabric Filter (DC-5)

The testing frequency for each emissions unit/point was established by the PSD permit, PSD-FL-010G. [Rule 62-297.310(7), F.A.C.; and, PSD-FL-010G, Table 6 (Revised) - Part B.]

D.9. Compliance Tests Prior To Renewal. Prior to permit renewal, a VE compliance test shall be performed for the following emission units/points:

E.U. ID No.	Brief Description
-023b	Conveyor C-3 Tunnel Ventilation (6,400 cfm)
-023b	Conveyor C-3 Tunnel Ventilation (21,600 cfm)
-023b	Conveyor C-3 Tunnel Ventilation (21,600 cfm)
-0231	Limestone Reclaim Hopper with Fabric Filter (3DC-01)
-0231	Limestone Silos with Fabric Filters (2: 1DC-01 and 2DC-01)
-0231	Quick Lime Silo with Fabric Filter (used for water treatment)
-0231	Fuel Handling Building with Fabric Filter (DC-3)
-0231	Unit #1 Fuel Storage Bins with Fabric Filter (DC-4)
-0231	Unit #2 Fuel Storage Bins with Fabric Filter (DC-5)

The testing frequency for each emissions unit/point was established by the PSD permit, PSD-FL-010G. [Rule 62-297.310(7)(a)3., F.A.C.; and, PSD-FL-010G, Table 6 (Revised) - Part B.]

D.10. 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.]

D.11. Visible Emissions. Visible emissions tests shall be performed for the affected emissions points in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations for compliance purposes, in accordance with the testing frequency established in the table, and while using EPA Method 9, 40 CFR 60 , Appendix A, and Chapter 62-297, F.A.C. [PSD-FL-010; PA 81-13; Part V, Rule 2.501, JEPB; and, 0310045-015-AC/PSD-FL-010G.]

Recordkeeping and Reporting Requirements

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

D.12. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**D.13.**

[Rule 62-210.700(6), F.A.C.]

D.13. Malfunction Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

D.14. Test Reports.

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the ERMD-EQD on the results of each such test.

b. The required test report shall be filed with the ERMD-EQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.; Part XI, Rule 2.1101, JEPB]

Miscellaneous Requirements.

D.15. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

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

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

D.16. NSPS Requirements - Subpart Y. Except as otherwise provided in this permit, this emissions unit/points shall comply with all applicable provisions of 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants, adopted and incorporated by reference in Rule 62-204.800(8)(b)31., F.A.C. This emissions unit/points shall comply with **Appendix 40 CFR 60 Subpart Y** included with this permit. [Rule 62-204.800(8)(b)2., F.A.C.]

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

E.U. ID No.	**Brief Description**
-022	SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations

-022a	Gypsum Dewatering Building
-022a	Gypsum Storage Enclosure
-022j	Gypsum Truck Loadout
-022j	Fly Ash Loadout for Silo 1A (metal structure)
-022j	Fly Ash Loadout for Silo 1B (metal structure)
-022j	Fly Ash Loadout for Silo 2A (metal structure)
-022j	Fly Ash Loadout for Silo 2B (metal structure)
-022k	Solid Waste Disposal Area
-022l	Saleable Fly Ash Silo 1A with Fabric Filter (concrete structure)
-022l	Saleable Fly Ash Silo 1B with Fabric Filter (concrete structure)
-022l	Saleable Fly Ash Silo 2A with Fabric Filter (concrete structure)
-022l	Saleable Fly Ash Silo 2B with Fabric Filter (concrete structure)
-022l	Non-Saleable Fly Ash Silo Unit 1 with Fabric Filter (concrete structure)
-022l	Non-Saleable Fly Ash Silo Unit 2 with Fabric Filter (concrete structure)
-022m	Wet Fly Ash Loadout 1A/1B
-022m	Bottom Ash Loadout 1A/1B
-022m	Wet Fly Ash Loadout 2A/2B
-022m	Bottom Ash Loadout 2A/2B
-022n	Unpaved Road, By-Product Transport

Fugitive particulate matter emissions are generated from bottom ash, fly ash and gypsum materials handling and storage operations. This emissions unit/points are as depicted in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations [PSD-FL-010, and as amended (was originally Tables 2 and 6)]. Particulate matter emissions and visible emissions are controlled using fabric filter systems, water sprays, wetting agents, and full enclosures or partial enclosures, covers and wind screens, where appropriate and required by permit. Visible emissions limits shall be used for compliance purposes.

{Permitting notes: This emissions unit/points are regulated under Rule 62-212.400(5), PSD NSR Review, which includes BACT [dated 05/07/81; PSD-FL-010, and as amended ((A) thru (E))]; PA 81-13, and as amended); and, 0310045-012-AC/PSD-FL-010(G).}

<u>Essential Potential to Emit (PTE) Parameters</u>

E.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.; Part III, Rule 2.301, JEPB]

E.2. Air Quality Control Systems (AQCS). The permittee shall maintain and continue to use the AQCS established in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations, to minimize particulate matter emissions. [Rules 62-4.070(3) and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended October 28, 1986; PSD-FL-010C, clerked July 29, 1999; 0310045-012-AC/PSD-FL-010E; and, 0310045-015-AC/PSD-FL-010G]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition Nos. **E.3.** and **E.4.** are based on the specified averaging time of the applicable test method.

E.3. This emissions unit/points are subject to Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations, and it is attached. [PSD-FL-010; BACT; PA81-13; PSD-FL-010, amended October 28, 1986; PSD-FL-010C, clerked July 29, 1999; 0310045-012-AC/PSD-FL-010E; and, 0310045-015-AC/PSD-FL-010G]

E.4. Visible Emissions. Visible emissions (VE) shall be used for compliance purposes and shall not exceed the following opacity limits as established in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations:

E.U. ID No.	**Brief Description**	**VE Limit (% opacity)**
-022	SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations	
-022a	Gypsum Dewatering Building	5
-022a	Gypsum Storage Enclosure	5
-022j	Gypsum Truck Loadout	5
-022j	Fly Ash Loadout for Silo 1A (metal structure)	10
-022j	Fly Ash Loadout for Silo 1B (metal structure)	10
-022j	Fly Ash Loadout for Silo 2A (metal structure)	10
-022j	Fly Ash Loadout for Silo 2B (metal structure)	10
-022k	Solid Waste Disposal Area	10
-022l	Saleable Fly Ash Silo 1A with Fabric Filter (concrete structure)	5
-022l	Saleable Fly Ash Silo 1B with Fabric Filter (concrete structure)	5
-022l	Saleable Fly Ash Silo 2A with Fabric Filter (concrete structure)	5
-022l	Saleable Fly Ash Silo 2B with Fabric Filter (concrete structure)	5
-022l	Non-Saleable Fly Ash Silo Unit 1 with Fabric Filter (concrete structure)	5
-022l	Non-Saleable Fly Ash Silo Unit 2 with Fabric Filter (concrete structure)	5
-022m	Wet Fly Ash Loadout 1A/1B	10
-022m	Bottom Ash Loadout 1A/1B	10
-022m	Wet Fly Ash Loadout 2A/2B	10
-022m	Bottom Ash Loadout 2A/2B	10

-022n	Unpaved Road, By-Product Transport	10

[PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended October 28, 1986; PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part B; 0310045-012-AC/PSD-FL-010E; and, 0310045-015-AC/PSD-FL-010G]

Excess Emissions

E.5. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) 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.; and, Part III, Rule 2.301, JEPB]

E.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. [Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Test Methods and Procedures

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

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

E.8. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), the following emissions units/points shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions:

E.U. ID No.	Brief Description
-022l	Saleable Fly Ash Silo 1A with Fabric Filter (concrete structure)
-022l	Saleable Fly Ash Silo 1B with Fabric Filter (concrete structure)
-022l	Saleable Fly Ash Silo 2A with Fabric Filter (concrete structure)
-022l	Saleable Fly Ash Silo 2B with Fabric Filter (concrete structure)
-022l	Non-Saleable Fly Ash Silo Unit 1 with Fabric Filter (concrete structure)
-022l	Non-Saleable Fly Ash Silo Unit 2 with Fabric Filter (concrete structure)

The testing frequency for each emissions unit/point was established by the PSD permit, PSD-FL-010G. [Rule 62-297.310(7), F.A.C.; and, PSD-FL-010G, Table 6 (Revised) - Part B.]

E.9. Compliance Tests Prior To Renewal. Prior to permit renewal, a VE compliance test shall be performed for the following emission units/points:

E.U. ID No.	Brief Description

-022I	Saleable Fly Ash Silo 1A with Fabric Filter (concrete structure)
-022I	Saleable Fly Ash Silo 1B with Fabric Filter (concrete structure)
-022I	Saleable Fly Ash Silo 2A with Fabric Filter (concrete structure)
-022I	Saleable Fly Ash Silo 2B with Fabric Filter (concrete structure)
-022I	Non-Saleable Fly Ash Silo Unit 1 with Fabric Filter (concrete structure)
-022I	Non-Saleable Fly Ash Silo Unit 2 with Fabric Filter (concrete structure)

The testing frequency for each emissions unit/point was established by the PSD permit, PSD-FL-010G. [Rule 62-297.310(7)(a)3., F.A.C.; and, PSD-FL-010G, Table 6 (Revised) - Part B.]

E.10. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

E.11. Visible Emissions. Visible emissions tests shall be performed for the affected emissions points in Appendix SJRPP: Table 6 (Revised) - Part B, SJRPP: Materials Handling and Storage Operations for compliance purposes, in accordance with the testing frequency established in the table, and while using EPA Method 9, 40 CFR 60, Appendix A, and Chapter 62-297, F.A.C. [PSD-FL-010; PA 81-13; Part V, Rule 2.501, JEPB; and, 0310045-015-AC/PSD-FL-010G]

Recordkeeping and Reporting Requirements

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

E.12. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**E.13.**

[Rule 62-210.700(6), F.A.C.]

E.13. Malfunction Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

E.14. Test Reports.

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the ERMD-EQD on the results of each such test.
b. The required test report shall be filed with the ERMD-EQD as soon as practical but no later than 45 days after the last sampling run of each test is completed. [Rule 62-297.310(8), F.A.C.]

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

E.U. ID No.	Brief Description
-024	SJRPP: Cooling Towers (2)

Fugitive particulate matter emissions from the two cooling towers are controlled with drift eliminators. No mass testing requirement shall be imposed due to the physical layout.

{Permitting note: This emissions unit is regulated under Rule 62-212.400(5), PSD NSR Review (see PSD-FL-010 issued March 12, 1982, and amended October 28, 1986); PSD-FL-010C, clerked July 29, 1999.}

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

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.; Part III, Rule 2.301, JEPB; PSD-FL-010 and PA 81-13]

F.2. Controls. The permittee shall maintain and continue to use drift elimination to minimize particulate matter emissions. [Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended October 28, 1986; and, PSD-FL-010C, clerked July 29, 1999]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition Nos. **F.3.** and **F.4.** is based on the specified averaging time of the applicable test method.

F.3. This emissions unit/points are subject to Appendix SJRPP: Table 6 (Revised) - Part A, SJRPP, amended July 29, 1999, and it is attached. [PSD-FL-010; BACT; PA 81-13; PSD-FL-010, amended October 28, 1986; and, PSD-FL-010C, clerked July 29, 1999]

F.4. Particulate Matter. Particulate matter emissions from each cooling tower shall not exceed 67 lbs/hr[1]. No mass testing requirement shall be imposed due to the physical layout. [PSD-FL-010; PA 81-13; and, [1]PSD-FL-010C (clerked July 29, 1999), Table 6 (Revised) - Part A.]

Test Methods and Procedures

F.5. 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. {Permitting note: No mass testing is required, however, special compliance testing could be required.} [Rule 62-297.310, F.A.C.]

Recordkeeping and Reporting Requirements

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

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

E.U. ID No.	Brief Description
-026	NGS Circulating Fluidized Bed Boiler No. 2
-027	NGS Circulating Fluidized Bed Boiler No. 1

These emissions units are two coal, coal coated with latex, petroleum coke, and landfill gas fired circulating fluidized bed (CFB) boilers. These boilers are connected to the existing steam turbines of the retired Boilers Nos. 1 and 2 (297.5 MW each) as part of the repowering project authorized under air construction permit, No. 0310045-003-AC/PSD-FL-265. A dual-flued 495-foot stack was added to the facility for Repowered Units 1 and 2, along with solid fuel delivery and storage facilities, limestone preparation and storage facilities (including three limestone dryers), a lime silo, aqueous ammonia storage, polishing scrubbers, precipitators or baghouses, ash removal and storage facilities, and an electrical substation. The stack diameter is 15 feet, exit temperature is 144 degrees F and the actual stack gas flow rate is 700,000 acfm.

JEA is allowed to burn 195 standard cubic feet per minute (scfm) of landfill gas in the CFB Boiler Nos. 1 and 2 (total). The 195 scfm of landfill gas is equivalent to a heat input of 6 MMBtu/hr. The landfill gas is being generated from the adjacent North Landfill (Facility ID No. 0310340) operated by the City of Jacksonville which is located directly north of the JEA NGS/SJRPP/ST power plant at 11405 Island Drive in Duval County. The maximum sulfur content, as H_2S, of the landfill gas is expected to be 48.2 parts per million volume dry (ppmvd). The natural gas presently being combusted in the CFB boilers typically contains 34 ppmvd of H_2S.

Each NGS CFB boiler is equipped with a selective non-catalytic reduction (SNCR) system to reduce NO_X emissions, limestone injection to reduce SO_2 emissions, fabric filter to reduce particulate matter (PM & PM_{10}) emissions, while maximizing combustion efficiency and minimizing NO_X formation to limit CO and VOC emissions.

The CFB boiler Nos. 1 and 2 are equipped with mercury (Hg) CEMS which were manufactured by Thermo Scientific, Model 801-ADFNCB. CFB boiler Nos. 1 and 2 began operation in February 2002 and May 2002, respectively.

{Permitting notes: The emissions units are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(8)(b)2., F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration [PSD; PSD-FL-265; PSD-FL-265(A, B & C)]; and, Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination; and, Compliance Assurance Monitoring (CAM), adopted and incorporated in Rule 62-204.800, F.A.C.; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

G.1.1. Permitted Capacity. The maximum operation heat input rates are as follows:

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
-026	2,764	Natural Gas, No. 2 Fuel Oil, Coal and Petroleum Coke
-027	2,764	Natural Gas, No. 2 Fuel Oil, Coal and Petroleum Coke

These rates are included only for purposes of determining capacity during compliance stack tests. Continuous compliance with these rates is not required; and, capacity during compliance testing shall be determined based on fuel flow data and the as-fired heat content of the fuel. [Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.; and, 0310045-003-AC/PSD-FL-265.]

G.1.2. Permitted Capacity. The maximum landfill gas firing rate for the CFB Boiler Nos. 1 and 2 is as follows:

E.U. ID No.	scf/hr
-026 and -027	11,700 (total)

Landfill gas may be burned in combination with other authorized fuels provided the maximum heat input to each boiler is not exceeded. [Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.; and, Application No. 0310045-027-AC.]

{Permitting notes: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program (40 CFR Part 75) conservatively overestimates heat input ratings. The monitoring data for heat input is, therefore, not appropriate for purposes of compliance, including annual compliance certifications.}

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

G.3. Methods of Operation. Only coal, coal treated with a latex binder, petroleum coke, No. 2 fuel oil (maximum sulfur content of 0.05 percent, by weight), and natural gas, shall be fired in Units 1 and 2. {Permitting note: Fuel additives, such as naturally occurring clays containing kaolinite or montmorillonite, along with olivine, bauxite or granite in the form of a raw material and/or as a component of coal bottom ash may be used to prevent agglomeration of the bed material in the boilers. The Department and the Compliance Authority shall be notified in writing if a new source or type of fuel additive is desired to be evaluated for approval.} [Rule 62-213.410, F.A.C.; 0310045-003-AC/PSD-FL-265; and, 0310045-012-AC]

G.4. Hours of Operation. These emissions units are allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.; and, 0310045-003-AC/PSD-FL-265]

Air Pollution Control Technology

G.5.1. Sulfur Dioxide, Acid Gases and Metals Control. Sulfur dioxide (SO_2) and acid gases shall be controlled by the injection of limestone into the CFB boiler beds. Residual sulfur dioxide, acid gases and metals shall be further controlled by the use of add-on air quality control systems for Units 1 and 2. The add-on air quality control systems installed by JEA and approved by the Department are spray dryer absorber (SDA) systems (one for Unit 1 and one for Unit 2) and fabric filters (one for Unit 1 and one for Unit 2). During periods when an SDA is non-operational due to malfunction, maintenance or repair, limestone injection to the associated CFB boiler shall be increased to the extent needed to ensure that the SO_2 emission limits in Specific Condition No. **G.8.** for Units 1 and 2 of 0.2 lb/mmBtu, 24-hr block average, and 0.15 lb/mmBtu, 30-day rolling average are achievable. Non-operation of the SDA is limited to a maximum of 12 hours per month per unit (12-month rolling average). [Applicant Request; and 0310045-022-AC/PSD-FL-265E, specific condition 9.]

G.5.2. Sulfur Dioxide (SO_2). The permittee shall inject limestone into the CFB boiler beds or use the spray dryer absorber as necessary to maintain SO_2 emissions within permit limits as recorded by the continuous emissions monitoring system (CEMS) at all times. [Rules 62-4.070(1) and (3) (Reasonable Assurance), and 62-213.440(1) (Assurance of Compliance), F.A.C.; and, Permit No. 0310045-027-AC.]

G.6. Oxides of Nitrogen Control. A selective non-catalytic reduction (SNCR) system designed to meet a limit of 0.09 lb/MMBtu, 30-day rolling average, shall be used for control of oxides of nitrogen (NO_X) emissions. [Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.7. Particulate Matter Control. Particulate matter (PM and PM_{10}) shall be controlled by the use of high efficiency, add-on air quality control devices (either fabric filters or electrostatic precipitators) that are designed to meet a limit of 0.011 lb/MMBtu. [Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions Nos. **G.8.** thru **G.18.** are based on the specified averaging time of the applicable test method.

G.8. Best Available Control Technology. The following Table 1 is a summary of the BACT determinations by the Department and other limits requested by the applicant, as noted:

Table 1: Emission Limits for CFB Units 1 and 2

Pollutant	Emission Limits - Per Unit
Visible emissions	10 percent opacity, 6-minute block average
SO_2 [2]	0.2 lb/MMBtu, 24-hour block average [2,3] 0.15 lb/MMBtu, 30-day rolling average [2]
NO_X [1]	0.09 lb/MMBtu, 30-day rolling average [4]
PM/PM_{10} [1]	0.011 lb/MMBtu, 3-hour average [1]
CO [1]	350 lbs/hour, 24-hour block average [1,3]
VOCs [1]	14 lbs/hour, 3-hour average [1]
Pb [2]	0.07 lb/hour, 3-hour average [2]
H_2SO_4 [2]	1.1 lbs/hour, 3-hour average [2]
HF [1]	0.43 lb/hour, 3-hour average [1]
Hg [1]	0.03 lb/hour, 6-hour average [1]

[1] BACT determination.

[2] Requested by applicant.

[3] 24-hour block averages are calculated from midnight to midnight.

[4] Equivalent to approximately 0.8-0.9 lb/MW-hr (gross energy output).

[Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.9. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, 6-minute block average, excluding periods of startup, shutdown, and malfunction. [Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.10. Sulfur Dioxide.

a. Sulfur dioxide (SO_2) emissions from CFB Boilers Nos. 1 and 2 shall not exceed 0.20 lb/MMBtu (24-hour block average) nor 0.15 lb/MMBtu (30-day rolling average).
b. Sulfur dioxide from CFB Boilers Nos. 1 and 2 and existing Boiler No. 3 combined shall not exceed 12,284 tons during any consecutive 12-month period on a rolling basis.

[Applicant Request; and, 0310045-003-AC/PSD-FL-265]

G.11. Oxides of Nitrogen.

a. Oxides of nitrogen (NO_X) emissions from CFB Boilers Nos. 1 and 2 shall not exceed 0.09 lb/MMBtu on a 30-day rolling average basis.

b. Oxides of nitrogen emissions from CFB Boilers Nos. 1 and 2 and existing Boiler No. 3 combined shall not exceed 3,600 tons during any consecutive 12-month period on a rolling basis.

[Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.12. Particulate Matter (PM and PM_{10}).

a. Particulate matter (PM) emissions from CFB Boilers Nos. 1 and 2 shall not exceed 0.011 lb/MMBtu (3-hour average).

b. Particulate matter-10 microns or smaller (PM_{10}) emissions from CFB Boilers Nos. 1 and 2 shall not exceed 0.011 lb/MMBtu (3-hour average).

c. Stack emissions of particulate matter (PM) from CFB Boilers Nos. 1 and 2 and existing Boiler No. 3 combined shall not exceed 881 tons during any consecutive 12-month period on a rolling basis.

[Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.13. Carbon Monoxide. Carbon monoxide (CO) emissions shall not exceed 350 lbs/hour, 24-hour block average, nor 1533 tons per year from either CFB Boiler No. 1 or No. 2. [Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.14. Volatile Organic Compounds. Volatile organic compound (VOC) emissions shall not exceed 14 lbs/hour (3-hour average), nor 61.5 tons per year from either CFB Boiler No. 1 or No. 2. [Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.15. Lead. Lead (Pb) emissions shall not exceed 0.07 lb/hour (3-hour average), from either CFB Boiler No. 1 or No. 2. [Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.16. Sulfuric Acid Mist. Sulfuric acid mist (H_2SO_4) emissions shall not exceed 1.1 lbs/hour (3-hour average), from either CFB Boiler No. 1 or No. 2. [Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.17. Hydrogen Fluoride. Hydrogen fluoride (HF) emissions shall not exceed 0.43 lb/hour (3-hour average), from either CFB Boiler No. 1 or No. 2. [Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.18. Mercury. Mercury (Hg) emissions shall not exceed 0.03 lb/hour (6-hour average), from either CFB Boiler No. 1 or No. 2. [Applicant Request; Rule 62-212.400, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

Excess Emissions

The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of an NSPS or NESHAP provision.

G.19. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed the limitations established in Specific Condition **G.22.** [Rule 62-210.700(1), F.A.C.; and, 0310045-015-AC/PSD-FL-265C]

G.20. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in Appendix Q

Protocol for Startup and Shutdown. [Rule 62-210.700(1), F.A.C. and Proposed by the Applicant in the Renewal Application]

G.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.]

G.22. Excess Emissions - Authorized Emissions.

(1) Notwithstanding other emission limits and standards established by this permit, excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided (1) that best operational practices are adhered to and (2) the duration of excess emissions shall be minimized but not exceed sixty (60) hours in any calendar month per emissions unit (CFBs Units Nos. 1 and 2). The permittee shall keep operational records necessary to demonstrate compliance with this restriction. Emissions data collected during periods of startup, shutdown, and malfunction shall be included when determining compliance with annual emission limits. The CFB Units shall not be started up at the same time. The permittee shall update the written procedure summarizing the current best operational practices to be followed every 5 years (at operating permit renewal). Pursuant to Rule 62-210.200, F.A.C., Definitions, the following are defined:

a. *Startup.* The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
b. *Shutdown.* The cessation of the operation of an emissions unit for any purpose.
c. *Malfunction.* Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

See 40 CFR 60.7 and Rule 62-210.700(6), F.A.C. for reporting of excess emissions. [Rules 62-210.200, 62-210.700(1) & (5), F.A.C.; and, 0310045-015-AC/PSD-FL-265C]

(2) Notwithstanding other emission limits and standards established by this permit, excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided (1) that best operational practices are adhered to and (2) the duration of excess emissions shall be minimized but not exceed sixty (60) hours during any 30 consecutive calendar days per emissions unit (CFBs Units Nos. 1 and 2). The permittee shall keep operational records necessary to demonstrate compliance with this restriction. Emissions data collected during periods of startup, shutdown, and malfunction shall be included when determining compliance with annual emission limits. The CFB Units shall not be started up at the same time. The permittee shall update the written procedure summarizing the current best operational practices to be followed every 5 years (at operating permit renewal). Pursuant to Rule 62-210.200, F.A.C., Definitions, the following are defined:

a. *Startup.* The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
b. *Shutdown.* The cessation of the operation of an emissions unit for any purpose.
c. *Malfunction.* Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

See 40 CFR 60.7 and Rule 62-210.700(6), F.A.C. for reporting of excess emissions. [Rules 62-210.200, 62-210.700(1) & (5), F.A.C.; and, 0310045-015-AC/PSD-FL-265C; and, applicant requested]

Monitoring of Operations

G.23. Compliance Assurance Monitoring (CAM) Requirements. These emissions units are subject to the CAM requirements contained in the attached Appendix CAM: NGS CFB Boilers Nos. 1 and 2. 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(7)(b), F.A.C. [40 CFR 64; and, Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Monitoring Requirements

G.24. Continuous Emissions Monitoring Systems. The permittee shall install, calibrate, operate, and maintain Continuous Emission Monitoring Systems (CEMS) in the stack to measure and record the sulfur dioxide, oxides of nitrogen, carbon monoxide, mercury (Hg) and visible emissions from CFB Boilers Nos. 1 and 2. An emission level above a BACT limit, considering the 6-minute, 24-hour and 30-day rolling average periods, as applicable, shall be reported to the ERMD-EQD pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems shall comply with the certification, performance specifications, and quality assurance, and other applicable requirements of 40 CFR Part 75 and 40 CFR Part 60 (Appendix B), as indicated above. Periods of startup, shutdown, and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the limits in Table 1 of Specific Condition No. **G.8.** following the format of 40 CFR 60.7 (As revised, 64 Fed Reg. 7458 (Feb. 12, 1999)). {Permitting note: 40 CFR 75 does not address RATA requirements for CO CEMS. The required annual RATA testing for the CO CEMS shall be performed instead as required by 40 CFR 60 Appendix B.} [0310045-022-AC/PSD-FL-265E, specific condition 50.(a).]

Hg Continuous Emissions Monitoring Systems Operation. The permittee has voluntarily agreed to install and operate Hg CEMS on Units 1 and 2. The Hg CEMS were installed and operational in 2009, and shall be operated in accordance with the quality assurance/quality control (QA/QC) plan submitted by JEA and approved by the Department. The attached **Appendix Hg CEMS - Quality Assurance Plan** is a part of this permit. Any future revisions to the QA/QC plan that are approved by the Department will also be part of the permit. This requirement will stay in effect until such time that the state or EPA passes a regulatory requirement for mercury detailing the Hg CEMS operational protocol, at which time that rule will become the preferred protocol. The annual relative accuracy test required by the QA/QC plan can be performed by the permittee under the normal mode of operation. For JEA, the normal mode of operation is firing a fuel blend which is typically 15% coal and 85% petroleum coke. Every reasonable effort should be made by the permittee for the Hg CEMS to be operating during the time periods when the SDA is off-line. If the Hg CEMS is not operating during a time period when the SDA is taken off-line, the best estimate of Hg emissions shall be provided to the Department and EQD based on the requirements of Rule 62-210.370, F.A.C. [Rules 62-4.070(3) and 62-210.370, F.A.C.; and 0310045-022-AC/PSD-FL-265E, specific condition 50.(b).]

Continuous Emissions Monitoring Systems Reporting. JEA shall submit to the Department and EQD the Hg CEMS emissions data for both Units 1 and 2. It shall be submitted in a graphical representation of Hg emissions against time. The graph shall also indicate the periods when the SDA was taken off-line. The four quarterly Hg CEMS data shall be submitted starting on June 30, 2009 and ending on June 30, 2010 and thereafter Hg CEMS data shall be submitted semi-annually until June 2012. The submittal of Hg CEMS data after June 2012 will be only upon request from the Department or EQD. [Rule 62-4.070(3), F.A.C.; and 0310045-022-AC/PSD-FL-265E, specific condition 50.(c).]

Compliance Determination - Test Methods and Procedures

G.25. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 5, 5B, 8 17 or 29	Methods for Determining Particulate Matter Emissions

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 201 or 201A	Methods for Determining PM_{10} Emissions
EPA Methods 6, 6A, 6B, or 6C	Methods for Determining Sulfur Dioxide Emissions
Method 7, Method 7A, 7C, 7D, or 7E	Determination of Nitrogen Oxide Emissions
EPA Method 19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

G.26. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for PM_{10}, nitrogen oxides, sulfur dioxide, carbon monoxide and visible emissions. The NO_X, SO_2 and CO RATA test data used may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

G.27. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, CO, VOC, NO_X and SO_2. [Rule 62-297.310(7)(a)3., F.A.C.]

G.28. 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.]

G.29. Performance Tests and CEMS Certifications. Annual compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on CFB Boilers Nos. 1 and 2 while firing either coal or petroleum coke as indicated below. No stack tests are required if continuous emissions monitoring systems are used to demonstrate compliance pending EPA approval, otherwise initial performance tests shall be conducted as described above. Certification tests (or performance evaluations, as applicable) for all Continuous Emissions Monitoring System (CEMS) required by this permit must be completed within 60 days after achieving the maximum production rate at which each unit will be operated but not later than 90 days of initial operation, and prior to the initial stack tests for that Unit. No methods other than the ones identified below may be used for compliance testing unless prior DEP or the ERMD-EQD approval is received in writing. DEP or the ERMD-EQD may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated. [0310045-003-AC/PSD-FL-265]

G.30. Visible Emissions (Opacity). Compliance with the visible emissions limit in Specific Condition **G.9.** shall be demonstrated with continuous opacity monitors installed, certified, operated, and maintained in accordance with 40 CFR Part 75, based on 6-minute block averages and excluding periods of startup, shutdown, and malfunction. [0310045-003-AC/PSD-FL-265]

G.31. Sulfur Dioxide.

a. Compliance with sulfur dioxide (SO_2) emissions limits in Specific Condition **G.10.a.** shall be demonstrated with Continuous Emissions Monitoring Systems (CEMS) installed, certified, operated and maintained in accordance with 40 CFR Part 75, based on 24-hour block and 30-day rolling averages, as applicable, and excluding periods of startup, shutdown, and malfunction. Emissions recorded in parts per million shall be converted to lb/MMBtu using an appropriate F-factor for purposes of determining compliance with the emission limits in Specific Condition **G.10.a**.

b. Compliance with the annual SO_2 emission limit in Specific Condition **G.10.b.** shall be determined based on SO_2 data from the CEMS. Emissions during periods of startup, shutdown, and malfunction shall be considered in determining the total annual emissions.

c. At least three (3) hours of data are required to establish a 24-hour average for CEMS data.

[Applicant's request; 0310045-012-AC/PSD-FL-265B; and, 0310045-015-AC/PSD-FL-265C]

G.32. Oxides of Nitrogen.

a. Compliance with the oxides of nitrogen (NOx) emissions limit in Specific Condition **G.11.a.** shall be demonstrated with a CEMS installed, certified, operated and maintained in accordance with 40 CFR Part 75, based on a 30-day rolling average and excluding periods of startup, shutdown and malfunction. The 30-day rolling averages will be determined based on hourly values calculated in accordance with Appendix F of 40 CFR Part 75.

b. Compliance with the annual NO_X emissions limit in Specific Condition **G.11.b.** shall be determined by summing the products of hourly NO_X emission rate and heat input rate data from the CEMS. Emissions during periods of startup, shutdown, and malfunction shall be considered in determining the total emissions.

[Applicant's request; and, 0310045-015-AC/PSD-FL-265C]

G.33. Particulate Matter.

a. Annual compliance tests shall be performed on CFB Boilers Nos. 1 and 2 using EPA Methods 201 or 201A, to determine compliance with the particulate matter-10 microns or smaller (PM_{10}) limits in Specific Condition **G.12.b.** while firing petroleum coke. If petroleum coke has been fired for less than 400 hours during the previous federal fiscal year, the annual testing may be performed while firing coal.

b. Compliance with the annual particulate matter (PM) emissions limit in Specific Condition **G.12.c.** shall be determined using the following formula. This formula shall be used for each fuel consumed by each of CFB Boilers Nos. 1 and 2 and existing Boiler No. 3, and the resulting PM emissions summed to obtain a 12-month total for CFB Boilers Nos. 1 and 2 and existing Boiler No. 3.

PM Emissions = (Fuel Usage[a]) x (Emission Factor[b]) x unit conversion factors

Where:

[a] The "Fuel Usage" shall be measured by calibrated fuel flow meters (±5 percent accuracy) and recorded daily when a unit is operated.

[b] An "Emissions Factor" of [(9.19 x weight percent sulfur content) + 3.22] pounds per thousand gallons (lbs/10^3 gal) shall be used for fuel oil burned in existing Boiler No. 3. The weight percent sulfur content shall be determined based on an analysis of a representative sample of the fuel oil being consumed. The analysis shall be performed using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition. An "Emissions Factor" of 5 pounds per million cubic feet (lb/MCF) shall be used for natural gas burned in existing Boiler No. 3. For Repowered Units 1 and 2, the "Emissions Factor" shall be based on particulate matter stack test results using EPA Methods 5, 5B, 8, 17, or 29 for the individual units, and shall apply to the quantities of fuel consumed in the

individual units during the period immediately following the stack tests for the respective units until subsequent stack tests are completed.
[0310045-003-AC/PSD-FL-265]

G.34. Carbon Monoxide.

a. Compliance with the short-term carbon monoxide (CO) limit in Specific Condition **G.13.** shall be demonstrated with CEMS installed, calibrated, operated, and maintained in accordance with 40 CFR Part 60, Appendix B based on a 24-hour block average and excluding periods of startup, shutdown, and malfunction.
b. Compliance with the annual CO limit in Specific Condition **G.13.** shall be demonstrated by summing the products of hourly CO emission rate and heat input rate data from the CEMS. Emissions during periods of startup, shutdown, and malfunction shall be considered in determining the total emissions.

[0310045-003-AC/PSD-FL-265]

G.35. Valid Data. For the continuous monitoring systems required under Specific Conditions **G.31.a.**, **G.32.a.**, and **G.34.a.**, the permittee shall determine compliance based on CEMS data at the end of each operating day (midnight to midnight), new 24-hour block and 30-day average emission rates shall be calculated from the arithmetic average of all valid hourly emission rates during the previous 24-hours or 30 operating days, as appropriate. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200, F.A.C., where emissions exceed the standards in Table 1 (See Specific Condition **G.8.**). These excess emission periods shall be reported as required in 40 CFR 60.7. A valid hourly emission rate shall be calculated for each hour in which at least two concentrations are obtained at least fifteen (15) minutes apart. [0310045-003-AC/PSD-FL-265]

G.36. Volatile Organic Compounds. Compliance tests shall be performed on Units 1 and 2 using EPA Method 18, 25, or 25A to determine compliance with the volatile organic compound (VOC) emission limit in Specific Condition **G.14.** while firing petroleum coke. Compliance testing shall be conducted once within every five (5) years thereafter while firing petroleum coke or coal. Compliance with the CO limits based on CEMS data shall be used as surrogates to indicate compliance with the VOC limits. [0310045-003-AC/PSD-FL-265]

G.37. Lead. Initial compliance tests only shall be performed on Unit 2 using EPA Method 12 or 29 to determine compliance with the lead emission limit in Specific Condition **G.15.** while firing coal and while firing petroleum coke. An additional compliance test shall be conducted once every five years at permit renewal on one of the units while firing petroleum coke or coal or any mix of the two fuels and with the SDA down for maintenance. On July 28, 2009, a compliance test for lead was conducted on approximately 80 percent pet coke and 20 percent coal with the SDA down for maintenance. Subsequently, if the normal fuel mix to the CFB boilers is changed to 25 percent (or greater) coal for a period of more than 15 days, and the SDA requires scheduled maintenance, then an additional compliance test shall be conducted at a typical fuel mix within 60 days after the change is made and while the SDA is down for maintenance. [Rule 62-4.070(3), F.A.C.; and 0310045-022-AC/PSD-FL-265E, specific condition 37.]

G.38. Sulfuric Acid Mist. Initial compliance tests only shall be performed on Unit 2 using EPA Method 8 to determine compliance with the sulfuric acid mist emission limit in Specific Condition **G.16.** while firing petroleum coke and while firing coal. In addition, compliance with the SO_2 limits based on CEMS data shall be used as a surrogate to indicate compliance with the sulfuric acid mist limit. [0310045-003-AC/PSD-FL-265]

G.39. Hydrogen Fluoride. Initial compliance tests only shall be performed on CFB Boiler No. 2 using EPA Method 13A or 13B to determine compliance with the hydrogen fluoride emission limit in Specific Condition **G.17.** while firing coal and while firing petroleum coke. [0310045-003-AC/PSD-FL-265]

G.40. Mercury. Initial compliance tests only shall be performed on CFB Boiler No. 2 using EPA Methods 29, 101, or 101A to determine compliance with the mercury emission limit in Specific Condition **G.18.** while firing coal and while firing petroleum coke. [0310045-003-AC/PSD-FL-265]

G.41. Distillate No. 2 Fuel Oil - Sulfur Content. Vendor or other fuel sampling and analysis data (using applicable ASTM methods) shall be used to determine that the sulfur content of the No. 2 fuel oil used in CFB Boilers Nos. 1 and 2 does not exceed 0.05%, by weight. [Rule 62-210.200, Definitions - PTE, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

Recordkeeping and Reporting Requirements

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

G.42. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**G.49.**
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**G.44.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

G.43. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, JEA shall notify the ERMD-EQD as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.44. Excess Emissions Report.

a. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD.
b. If excess emissions occur due to malfunctions for a period of more than two hours, the owner or operator shall notify ERMD-EQD within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may require a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A.

[0310045-003-AC/PSD-FL-265; and, Rule 62-210.700(6), F.A.C.]

G.45. Records. All measurements, records, and other data required to be maintained by JEA shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and ERMD-EQD representatives upon request. [Rules 62-4.070(3) and 62-213.440(1)(b)2.b., F.A.C.; and, 0310045-003-AC/PSD-FL-265]

G.46. Certification Testing of Monitors. As required under the federal Acid Rain Program, the Acid Rain Monitoring Plan for NGS shall be revised to address the new Continuous Emissions Monitoring Systems (CEMS) for sulfur dioxide, oxides of nitrogen, and visible emissions (opacity) for Repowered NGS Units 1 and 2. The permittee shall provide a copy of this revised plan, as well as model and serial numbers for each of the monitors, to ERMD-EQD within 45 days after completion of all certification tests. In addition, the permittee shall provide notification that the carbon monoxide CEMS meet the performance specifications in 40 CFR Part 60, Appendix B (as applicable), and also provide model and serial numbers to ERMD-EQD within 45 days after completion of the performance specification tests. [0310045-003-AC/PSD-FL-265]

G.47. Quarterly Compliance Reports for Annual Limits. The permittee shall provide reports quarterly to the ERMD-EQD certifying compliance with the 12-month rolling limits on SO_2, NO_X and PM (TSP) for NGS CFB Boilers Nos. 1 and 2 and existing Boiler No. 3 set forth in Specific Conditions **G.10.b.**, **G.11.b.**, and **G.12.c**. The reports shall be submitted within 45 days after the last day of each calendar quarter. [0310045-003-AC/PSD-FL-265]

General Operation Requirements

G.48. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.; and, 0310045-003-AC/PSD-FL-265]

Miscellaneous

G.49. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

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

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

G.50. NSPS Requirements - Subpart Da. Except as otherwise provided in this permit, the combustion turbine shall comply with all applicable provisions of 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(8)(b)2., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.47a. These emissions units shall comply with **Appendix 40 CFR 60 Subpart Da** included with this permit. [Rule 62-204.800(8)(b)2., F.A.C.]

G.51. Engineering Study to increase the Reliability and Availability of the SDA System. The permittee shall provide an engineering study by December 31, 2010 to the Department and EQD detailing opportunities to increase the reliability and availability of the SDA system. The study will address potential improvements in preventive and predictive maintenance, and potential equipment and system modifications (including opportunities for redundancy) which will result in minimizing the amount of time the SDA is off-line during CFB operation. The engineering study shall also include the cost estimates associated with potential equipment/system modifications (including opportunities for redundancy) and the cost effectiveness of the associated emissions reductions. [Rule 62-4.070(3), F.A.C.; and 0310045-022-AC/PSD-FL-265E, specific condition 49.]

G.52. Compliance Plan. Permit Number 0310045-027-AC authorized the combustion of landfill gas in the CFB Boiler Nos. 1 and 2.

a. Operation of the emissions units beyond the time frames established by the AC permit is allowed, provided the Department has received and verified properly signed and sealed certification statements from the Responsible Official (R.O.) and a licensed Florida Professional Engineer (P.E.) stating that: 1) the construction and modifications of the emissions units were completed in accordance with the AC permit; and, 2) compliance with the terms and conditions contained within the AC permit have properly been demonstrated prior to the expiration date of the AC permit.

b. The P.E. and R.O. certification statements from DEP Form No. 62-210.900(1) shall be used and must be submitted to the Department within 105 days after achieving the maximum rate at which the emissions units will be operated, but no later than 180 days after initially burning landfill gas in the boilers.

[Rules 62-213.440(2), and 62-213.420(1)(a)5., F.A.C.]

G.53. Source Obligation. A relaxation of the specific terms and conditions of this permit, as established by Permit No. 0310045-027-AC, may subject the facility to a BACT determination. Specifically, an increase in the quantity of landfill gas burned and/or the H_2S content of the landfill gas could trigger a BACT determination. {See Rule 62-212.400(12)(a) - (c), F.A.C.} Any request to change the specific terms and conditions of Permit No. 0310045-027-AC must be submitted to the Bureau of Air Regulation in the Division of Air Resource Management of the Florida Department of Environmental Protection. [Rule 62-212.400(12)(a) - (c) (Source Obligation), F.A.C.; and, Permit No. 0310045-027-AC, specific condition 3.A.1.]

Landfill Gas - Miscellaneous Requirements

G.54. Fuel Consumption Records. The permittee shall maintain, for each boiler, a daily log of the amount of landfill gas fired. [Rules 62-4.070(1) and (3) (Reasonable Assurance), and 62-213.440(1) (Assurance of Compliance), F.A.C.; and, Permit No. 0310045-027-AC.]

G.55. Test Reports. For each test run, the report shall also indicate the quantity of landfill gas burned. [Rule 62-297.310(8), F.A.C.; and, Permit No. 0310045-027-AC.]

G.56. Annual Operating Report (AOR). The permittee shall submit the quantity of landfill gas combusted in each boiler with the AOR. [Rules 62-4.070(1) and (3) (Reasonable Assurance), and 62-213.440(1) (Assurance of Compliance), F.A.C.; and, Permit No. 0310045-027-AC.]

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

E.U. ID No.	Brief Description
-028	NGS: Materials Handling and Storage Operations

-028	Belt Conveyor No. 1
-028a	Vessel Hold, Vessel Unloader and Spillage Conveyor
-028c	Transfer Building 1
-028d	Transfer Building 5 and limestone loadout chute
-028g	Transfer Building 2
-028h	Fuel Storage Domes A & B (includes fuel stackers/reclaimers)
-028i	Transfer Building 3
-028o	Plant Transfer Building
-028p	Limestone Storage Pile and Limestone Reclaim Hoppers
-028q	Transfer Building 4
-028v	Transfer Building 6

-029	NGS: Crusher House Building Baghouse Exhaust
-031	NGS: Fuel Silos Dust Collectors
-033	NGS: Limestone Dryers/Mills Building
-034	NGS: Limestone Prep Building Dust Collectors
-035	NGS: Limestone Silos Bin Vent Filters
-036	NGS: Fly Ash Transport Blower Discharge
-037	NGS: Fly Ash Silos Bin Vents
-038	NGS: Bed Ash Silos Bin Vents
-042	NGS: AQCS Pebble Lime Silo
-051	NGS: Fly Ash Slurry Mix System Vents
-052	NGS: Bed Ash Slurry Mix System Vents
-053	NGS: Bed Ash Surge Hopper Bin Vents

The material handling and storage operations process ash, limestone, coal, coal coated with latex, and petroleum coke to support the operation of CFB Boilers Nos. 1 and 2. Each materials handling and storage operation at NGS employs one or more control strategies to limit emissions of particulate matter to meet specific emission limitations and/or visible emissions limits. The control strategies include the use of best operating/design practices, total or partial enclosures, conditioned materials, wet suppression, water sprays, and dust collection systems. Except for the Belt Conveyor 1, all conveyors are enclosed. The fly and bed ash silos (E.U. ID No. -037 and E.U. ID No. -038) have the capability to unload into either trucks or rail cars

{Permitting notes: Emission Unit ID Nos. -029 & -031 are regulated under 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants (coal handling at NGS, excluding open storage piles), adopted and incorporated by reference in Rule 62-204.800(8)(b)31., F.A.C.. Emission Unit ID Nos. -033, -034 & -035 are regulated under Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants (limestone handling at NGS, except for open storage piles and truck unloading), adopted and incorporated by reference in Rule 62-204.800(8)(b)64., F.A.C.

Some of these emissions units are regulated under Rule 212.400(5), F.A.C., Prevention of Significant Deterioration [PSD; PSD-FL-265; 0310045-007-AC/PSD-FL-265A; and, 0310045-012-AC/PSD-FL-265B]; Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination; and, Rule 62-296.711, F.A.C., Reasonable Available Control Technology (RACT) - Materials Handling, Sizing, Screening, Crushing and Grinding Operations.}

Essential Potential to Emit (PTE) Parameters

H.1. Permitted Capacity.

a. Throughput Rates. The materials handling and usage rates for coal, coal coated with latex, petroleum coke, and limestone at NGS shall not exceed the following (for NGS CFB Boilers Nos. 1 and 2 combined), assuming a moisture content of 5.5% or less:

Material	Handling/Usage Rate Tons Per Year
Coal/Coal coated with latex/Petroleum Coke	2.42 million
Limestone	1.45 million

b. Heat Input Rates. The maximum heat input rates to the three limestone dryers shall not exceed 57.9 MMBtu/hr, for all three units combined. These rates are included only for purposes of determining capacity during compliance stack tests. Continuous compliance with these rates is not required; capacity during compliance testing shall be determined based on fuel flow data and the as-fired heat content of the fuel.

[Rule 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.; 0310045-003-AC/PSD-FL-265; and, 0310045-012-AC/PSD-FL-265B]

H.2. Hours of Operation. The Materials Processing Operations are allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.; Part III, Rule 2.301, JEPB]

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

H.4. Method of Operation.

a. *Material Processing Operations.* The emissions units either process or transfer materials used in the operations of NGS's CFBs Boilers Nos. 1 and 2. The transfer buildings (TBs) are numbered sequentially as they occur in the process with TB 1 being the TB nearest the vessel unloading operations and TB 5 being the TB immediately upstream of the fuel storage buildings and the limestone storage pile. TBs 1 thru 5 are associated with the transfer of raw coal, pet coke and limestone, while TB 6 is associated with the transfer of raw coal and pet coke and the Plant TB is associated with the transfer of crushed coal and pet coke. Limestone loadout via telescopic chute is included with TB 5. Except for the Belt Conveyor 1, all conveyors are enclosed.

b. *Fuels.* Limestone Dryers (3)(EU -033). Each limestone dryer is allowed to fire distillate fuel oil and Natural/Landfill Gases. The distillate fuel oil has a maximum sulfur content limit of 0.05%, by weight.

[Rule 62-213.410, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions Nos. **H.5., H.6.** and **H.7.** are based on the specified averaging time of the applicable test method.

H.5. <intentionally left blank>

H.6. Particulate Matter. The maximum particulate matter emissions from the following operations shall not exceed 0.01 grains per dry standard cubic foot:

a. Limestone dryers - each (3) (EU-033)

b. Limestone prep building dust collectors (EU-034)
c. Limestone silos bin vent filters (EU-035)

[0310045-003-AC/PSD-FL-265; and, 0310045-012-AC/PSD-FL-265B]

H.7. Visible Emissions. The materials processing sources at NGS shall be regulated as follows, and the emission limits and standards shall apply upon completion of the initial compliance tests for each of the emissions units or activities.

a. The following materials handling sources shall be equipped with fabric filter controls and visible emissions shall not exceed 5 percent opacity:
   (1) Crusher house building baghouse exhaust (EU-029)
   (2) Fuel silos dust collectors (EU-031)
   (3) Limestone dryers - each (3) (EU-033)
   (4) Limestone prep building dust collectors (EU-034)
   (5) Limestone silos bin vent filters (EU-035)
   (6) Fly ash transport blower discharge (EU-036)
   (7) Fly ash silos bin vents (EU-037)
   (8) Bed ash silos bin vents (EU-038)
   (9) AQCS pebble lime silo (EU-042)
   (10) Fly ash slurry mix system vents (EU-051)
   (11) Bed ash slurry mix system vents (EU-052)
   (12) Bed ash surge hopper bin vents (EU-053)
b. The following materials handling sources shall use wet suppression, water spray, coverings, and/or conditioned materials to control particulate emissions as needed, and visible emissions shall not exceed 5 percent opacity:
   (1) Transfer towers (EU-028c, EU-028g, EU-028i, EU-028o, EU-028q and EU-028v)
   (2) Coal, coal coated with latex and petroleum coke storage building (EU-028h)
   (3) Transfer Building 5 and limestone loadout chute (EU-028d)
   (4) Belt Conveyor No. 1 (EU-028)
c. The following materials handling sources shall use wet suppression, water spray, partial enclosures, and/or conditioned materials to control particulate emissions as needed, and visible emissions shall not exceed 10 percent opacity:
   (1) NGS dock vessel unloading operations - vessel hold (EU-028a)
   (2) NGS dock vessel unloading operations - vessel unloader and spillage conveyor (EU-028a)
   (3) Limestone storage pile (EU-028p)
   (4) Limestone reclaim hopper (EU-028p)
d. The limestone dryer/mill building shall have no visible emissions (other than from a baghouse vent).

[0310045-003-AC/PSD-FL-265; 0310045-007-AC/PSD-FL-265A; and, 0310045-012-AC/PSD-FL-265B)]

H.8. Distillate Fuel Oil Sulfur Content. The maximum sulfur content of the distillate No. 2 fuel oil that is allowed to be fired in each of the three (3) limestone dryers (EU-033) is 0.05%, by weight. [0310045-003-AC/PSD-FL-265]

Excess Emissions

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

H.9. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) 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.]

H.10. 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.]

Test Methods and Procedures

H.11. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Method 5	Methods for Determining Particulate Matter Emissions
EPA Method 9	Visual Determination of the Opacity of Emissions
EPA Method 22	Visual Determination of Fugitive Emissions from Material Sources

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

H.12. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit/points shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions. The testing frequency is established in the table in specific condition **H.19.** [Rule 62-297.310(7), F.A.C.]

H.13. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE. The testing frequency is established in the table in specific condition H.19. [Rule 62-297.310(7)(a)3., F.A.C.]

H.14. 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.]

H.15. Limestone Dryers (3): Distillate No. 2 Fuel Oil - Sulfur Content. Vendor or other fuel sampling and analysis data (using applicable ASTM methods) shall be used to determine that the sulfur content of the No. 2 fuel oil used in the three (3) limestone dryers does not exceed 0.05%, by weight. [Rule 62-210.200 (Definitions - PTE), F.A.C.; and, 0310045-003-AC/PSD-FL-265]

H.16. Limestone Dryers (3) - Visible Emissions (EU-033). Compliance with the visible emissions limit in Specific Condition **H.7.** for the limestone dryers (each) shall be demonstrated using EPA Method 9 initially and once within every five years thereafter. The limestone dryers shall fire fuel oil during the initial compliance tests. In subsequent years, the testing shall be conducted annually if fuel oil has been fired for more than 400 hours during the previous federal fiscal year; otherwise, the testing shall be conducted once within every five years, even if the testing is conducted while firing natural gas. [0310045-003-AC/PSD-FL-265]

H.17. Limestone Dryers (3) - Particulate Matter (EU-033). Initial compliance tests only shall be performed on the limestone dryers (3) to determine compliance with the particulate matter limit in Specific Condition **H.6.** using EPA Method 5. [0310045-003-AC/PSD-FL-265]

H.18. Particulate Matter. Initial compliance tests only shall be performed on the limestone prep building dust collectors (EU-034) and the limestone silos bin vent filters (EU-035) to determine compliance with their particulate matter limit specified in Specific Condition **H.6.** using EPA Method 5, 40 CFR 60, Appendix A. The minimum sample volume shall be 30 dry standard cubic feet. [0310045-003-AC/PSD-FL-265; 40 CFR 60, Appendix A; and, Rule 62-296.711(3)(b), F.A.C.]

H.19. Visible Emissions (VE). VE tests shall be conducted on the following emissions units to determine compliance with their applicable limits, as follows:

Emissions Units at NGS	EPA Method(s)	Duration of VE Test	Frequency	Material
Vessel Hold (EU-028a)	9	30 min	I only	C or PC
Vessel Unloader & Spillage Conveyors (EU-028a)	9	3 hr	I only	C & LS
Belt Conveyor No. 1 (EU-028)	9	3 hr	I only	C & LS
Transfer Towers (EU-028c, -028g, -028i, -028o, -028q & -028v)	9	3 hr	I only	C & LS
Fuel Storage Building (EU-028h)	9	30 min	I only	C or PC
Limestone Storage Pile (EU-028p)	9	30 min	I only	LS
NSPS - OOO				
Limestone Prep Building Dust Collectors - Baghouse Exhaust (EU-034)	9-VE 5-PM	IVE - 60 min RVE - 30 min	Meth 9: I & R Meth 5: I only	LS
Limestone Silos Bin Vent Filters - Baghouse Exhaust (EU-035)	9-VE 5-PM	IVE - 60 min RVE - 30 min	Meth 9: I & R Meth 5: I only	LS
Limestone Dryer/Mill Building (EU-033)	22	IVE - 75 min	I only	LS
NSPS - Y				
Crusher House Building Baghouse Exhaust (EU-029)	9	IVE - 3 hr RVE - 30 min	I & R	C &/or PC
Fuel Silos Dust Collectors - Baghouse Exhaust (EU-031)	9	IVE - 3 hr RVE - 30 min	I & R	C &/or PC
Other				
Fly Ash Transport Blower Discharge - Baghouse Exhaust (EU-036)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Fly Ash Silos Bin Vents - Baghouse Exhaust (EU-037)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Bed Ash Silos Bin Vents - Baghouse Exhaust (EU-038)	9	IVE - 30 min RVE - 30 min	I & R	Ash
AQCS Pebble Lime Silo - Baghouse Exhaust (EU-042)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Fly Ash Slurry Mix System Vents - Baghouse Exhaust (EU-051)	9	IVE - 60 min RVE - 60 min	I & R	Ash
Bed Ash Slurry Mix System Vents - Baghouse Exhaust (EU-052)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Bed Ash Surge Hopper Bin Vents - Baghouse Exhaust (EU-053)	9	IVE - 60 min RVE - 60 min	I & R	Ash

C – Coal and/or Coal coated with latex
I – Initial R - Renewal (once every 5 years)
IVE – Initial Visible Emissions Test, RVE - Renewal Visible Emissions Test
LS – Limestone; PC-Petroleum Coke

Note: No methods other than the ones identified above may be used for compliance testing unless prior DEP or the ERMD-AQD approval is received in writing.
[0310045-003-AC/PSD-FL-265; 0310045-007-AC/PSD-FL-265A; 0310045-012-AC/PSD-FL-265B; 0310045-021-AC/PSD-FL-265D; 40 CFR 60.11(b); 40 CFR 60, Appendix A; 0310045-021-AC; and 0310045-015-AC/PSD-FL-010G.]

Recordkeeping and Reporting Requirements

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

H.20. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**H.22.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

H.21. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, JEA shall notify the ERMD-EQD as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.; and, 0310045-003-AC/PSD-FL-265]

H.22. Excess Emissions Report. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.]

If excess emissions occur due to malfunctions for a period of more than two hours, the owner or operator shall notify ERMD-EQD within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may require a written summary report of the incident. For EUs -029, -031, -033, -034 and -035, and pursuant to the Standards of Performance for New Stationary Sources at 40 CFR 60, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A.
[0310045-003-AC/PSD-FL-265]

H.23. Records. All measurements, records, and other data required to be maintained by JEA shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and the ERMD-EQD representatives upon request. [Rules 62-4.070(3) and 62-213.440(1)(b)2.b., F.A.C.; and, 0310045-003-AC/PSD-FL-265]

General Operation Requirements

H.24. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.; and, 0310045-003-AC/PSD-FL-265]

H.25. NSPS Requirements - Subpart A. Emission Unit Nos. -029, -031, -033, -034 & -035 shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions including:

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

adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

H.26. NSPS Requirements - Subpart Y. Except as otherwise provided in this permit, this emissions unit/points (Emission Unit Nos. -029 & -031) shall comply with all applicable provisions of 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants (coal handling at NGS, excluding open storage piles), adopted and incorporated by reference in Rule 62-204.800(8)(b)31., F.A.C. This emissions unit/points shall comply with **Appendix 40 CFR 60 Subpart Y** included with this permit. [Rule 62-204.800(8)(b)2., F.A.C.]

H.27. NSPS Requirements - Subpart OOO. Except as otherwise provided in this permit, these emissions units/points (Emission Unit Nos. -033, -034 & -035) shall comply with all applicable provisions of 40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants (limestone handling at NGS, except for open storage piles and truck unloading), adopted and incorporated by reference in Rule 62-204.800(8)(b)64., F.A.C. These emissions units/points shall comply with **Appendix 40 CFR 60 Subpart OOO** included with this permit. [Rule 62-204.800(8)(b)64., F.A.C.]

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

E.U. ID No.	Brief Description
-044	Separator A Filter - Receiver Vent
-045	Separator B Filter - Receiver Vent
-046	Separator Dust Collector Vent
-047	Clean-up Vacuum Vent
-048	Fly Ash Surge Bin Vent
-049	Mineral Additive Storage Bin Vent
-050	Gas-Fired Dryer Stack

Separations Technology, LLC (ST) has constructed, owns and operates a fly ash processing system on a portion of leased property at the JEA SJRPP facility in Duval County, Florida. The purpose of the equipment is to remove the residual carbon and ammonia from the SJRPP fly ash leaving a saleable product. As a result, environmental benefits include a 255,000 ton reduction in the fly ash currently sent to landfill by the JEA SJRPP each year and an overall reduction in the ammonia releases with the recovery and subsequent recycle of ammonia removed from the fly ash.

The fly ash processing system includes the addition of two fly ash receiving bins, a carbon separation unit, a clean-up vacuum, a fly ash surge bin, a mineral additive storage bin, and a gas-fired dryer. The particulate emissions generated from handling of the fly ash are collected from each source using pulse jet fabric filters. ST's triboelectric carbon separation technology partitions fly ash into mineral-rich and carbon-rich fractions. The mineral-rich fly ash can then be sold as a usable product. The carbon-rich fly ash is returned to the JEA SJRPP fly ash storage silos for eventual disposal at the onsite landfill or transported offsite.

The two-step beneficiation process consists of (1) removal of the residual carbon from the fly ash using ST's patented electrostatic separation technology, and (2) removal of residual ammonia from the fly ash using ST's ammonia removal technology (patent pending). In addition to residual carbon, the fly ash at the JEA SJRPP also contains trace amounts of ammonia that makes it unsuitable as a cement replacement. To solve this problem, ST installed an ammonia removal process. The recovered ammonia is subsequently returned to the JEA SJRPP for recycle.

{Permitting notes: The emissions units are permitted under Rule 212.400, F.A.C., Prevention of Significant Deterioration [PSD; 0310001-002-AC/PSD-FL-010(D)]; Rule 62-296.711, F.A.C., Reasonable Available Control Technology - Materials Handling, Sizing, Screening, Crushing and Grinding Operations; and, Rule 62-296.712, F.A.C., Reasonable Available Control Technology (RACT) -Miscellaneous Manufacturing Process Operations.}

Essential Potential to Emit (PTE) Parameters

I.1. Equipment Design Capacity. The equipment design of the fly ash processing operation is based on a maximum fly ash delivery rate from JEA SJRPP of 300,000 tons per year. [Rule 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

I.2. Hours of Operation. The operations are allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.; 0310001-002-AC/PSD-FL-010(D)]

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

I.4. Method of Operation.

a. Fly Ash Processing Operations. The operation processes fly ash from the JEA SJRPP facility. The two-step beneficiation process consists of (1) removal of the residual carbon from the fly ash using ST's patented electrostatic separation technology, and (2) removal of residual ammonia from the fly ash using ST's ammonia removal technology (patent pending). In addition to residual carbon, the fly ash at the JEA SJRPP also contains trace amounts of ammonia that makes it unsuitable as a cement replacement. To solve this problem, ST installed an ammonia removal process. The recovered ammonia is subsequently returned to the JEA SJRPP for recycle.
b. Fuel: For the boiler, the only fuel allowed to be fired is natural gas.

[Rule 62-213.410, F.A.C.; and, 0310001-002-AC/PSD-FL-010(D)]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions Nos. **I.5.** and **I.6.** are based on the specified averaging time of the applicable test method.

I.5. Particulate Matter. The maximum particulate matter emissions from the following operations shall not exceed:

a. 0.015 grains per dry standard cubic foot:
   (1) Separator A Filter - Receiver Vent (EU-044)
   (2) Separator B Filter - Receiver Vent (EU-045)
   (3) Separator Dust Collector Vent (EU-046)
   (4) Clean-up Vacuum Vent (-047)
   (5) Fly Ash Surge Bin Vent (-048)
   (6) Mineral Additive Storage Bin Vent (-049)
b. 1.60 lbs/hr:
   (1) Gas-Fired Dryer Stack (EU-050)
c. Visible Emissions. Visible emissions less than or equal to 5 percent opacity shall be considered in compliance with the particulate matter emissions limits established above.

[0310001-002-AC/PSD-FL-010(D)]

I.6. Visible Emissions.

a. Visible emissions shall not exceed 5 percent opacity for EU-044 thru EU-050.
b. Annual compliance certification shall be conducted to measure opacity.

[0310001-002-AC/PSD-FL-010(D)]

Excess Emissions

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

I.7. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) 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.]

I.8. 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.]

Test Methods

I.9. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

I.10. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit/points shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions. [Rule 62-297.310(7), F.A.C.]

I.11. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE. [Rule 62-297.310(7)(a)3., F.A.C.]

I.12. 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.]

I.13. Visible Emissions (VE). Annual compliance certification shall be conducted using EPA Method 9 tests to measure opacity. [0310001-002-AC/PSD-FL-010(D); and, 40 CFR 60, Appendix A; and, Rules 62-296.711(3)(a) and 62-296.712(3)(a), F.A.C.]

Recordkeeping and Reporting Requirements

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

I.14. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions, if requested by the ERMD-EQD	Every 3 months (quarter)	**I.16.**

[Rule 62-210.700(6), F.A.C.]

I.15. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, ST shall notify the ERMD-EQD as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

I.16. Excess Emissions Report. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the ERMD-EQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the ERMD-EQD. [Rule 62-210.700(6), F.A.C.]

I.17. Records. All measurements, records, and other data required to be maintained by ST shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and the ERMD-EQD representatives upon request. [Rules 62-4.070(3) and 62-213.440(1)(b)2.b., F.A.C.]

Operated by: JEA
Plant Name: Northside Generating Station and St. Johns River Power Park (NGS/SJRPP)
ORIS code: 0667: Northside Generating Station
0207: St. Johns River Power Park

Subsection A. This Subsection addresses Acid Rain, Phase II SO_2.

The emissions units listed below are regulated under Phase II of the federal Acid Rain Program.

E.U. ID No.	Brief Description
-001	NGS Boiler No. 1 (retired/dismantled)
-002	NGS Boiler No. 2 (retired/dismantled)
-003	NGS Boiler No. 3
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2
-026	NGS Circulating Fluidized Bed Boiler No. 2A (297.5 MW)
-027	NGS Circulating Fluidized Bed Boiler No. 1A (297.5 MW)

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

a. NGS. DEP Form No. 62-210.900(1)(a) - Form, Effective: 3/16/08, received on July 3, 2008, and signed by the Designated Representative on May 6, 2008, which is included at the end of this section.

b. SJRPP. DEP Form No. 62-210.900(1)(a) - Form, Effective: 3/16/08, received on July 3, 2008, and signed by the Designated Representative on May 6, 2008, which is included at the end of this section.

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

A.2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID No.	Year	2009	2010	2011	2012	2013
-003 [1]	3	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	11124*	6658*	6658*	6658*	6658*
-026 [1]	2A	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	6268*	1048*	1048*	1048*	1048*
-027 [1]	1A	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	6222*	4897*	4897*	4897*	4897*
-016 [2]	1	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	11582*	11605*	11605*	11605*	11605*
-017 [2]	2	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	11370*	11395*	11395*	11395*	11395*

[1] Northside Generating Station.
[2] St. Johns River Power Park.

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2, 3, or 4 of 40 CFR 73.

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

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

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

A.5. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator. [40 CFR 70.6(a)(1)(ii); and Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

A.6. Comments, notes, and justifications: None.

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
Northside	Florida	0667

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
1A	No	Yes		
2A	No	Yes		
3	No	Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

1

Northside
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,

Northside
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

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

3

Northside
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.

Michael Brost Name	Vice President, Electric Systems Title
JEA Owner Company Name	
(904) 665-7547 Phone	brosmj@jea.com E-mail address
Signature M Brost	Date 5-6-08

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

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
Saint Johns River Power Park	Florida	0207

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
1	No	Yes		
2	No	Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

1

Saint Johns River Power Park
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,

Saint Johns River Power Park
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

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

3

Saint Johns River Power Park
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.

Michael Brost Name	Vice President, Electric Systems Title
JEA Owner Company Name	
(904) 665-7547 Phone	brosmj@jea.com E-mail address
Signature [signature]	Date 5-6-08

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

Subsection B. This subsection addresses Acid Rain, Phase II NO_X.

{Permitting note: The U.S. EPA issued Acid Rain Phase I permit(s)}

The emissions units listed below are regulated under Acid Rain Part, Phase II NO_X, for:

JEA
St. Johns River Power Park
Facility ID No. 0310045
ORIS Code: 0207

E.U. ID No.	Brief Description
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

B.1. The Acid Rain Phase II NO_X Compliance Plan application(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. Phase II NO_X Compliance Plan, EPA Form 7610-28 (12-03), dated April 22, 2008, which is included at the end of this section.

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

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

E.U. ID No.	EPA ID No.	NO_X limit [1]
-016	1	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2009 through calendar year 2013. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.
-017	2	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2009 through calendar year 2013. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

[1] Based on the Phase II NO_X Compliance Plan, EPA Form 7610-28 (12-03), dated April 22, 2008.

B.3. Comments, notes, and justifications: none.

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Compliance Plan

Page [1] of [2]

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

This submission is: ☐ New ☒ Revised

STEP 1
Indicate plant name, State, and ORIS code from NADB, if applicable

Plant Name	State	ORIS Code
St. Johns River Power	FL.	207

STEP 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	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)	☐	☐	☐	☐	☐	☐
(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)	☐	☐	☐	☐	☐	☐

EPA Form 7610-28 (12-03)

St. Johns River Power
Plant Name (from Step 1)

NO_x Compliance - Page 2
Page 2 of 2

STEP 2, cont'd.

	ID# 1 Type DBW	ID# 2 Type DBW	ID# Type	ID# Type	ID# Type	ID# Type
(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 &

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 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.

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 ATHENA T. MANN	
Signature A T Mann	Date 04/22/2008

EPA Form 7610-28 (12-03)

SECTION V. APPENDICES.

The Following Appendices Are Enforceable Parts of This Permit:

Appendix A, Glossary.
Appendix ASP, ASP Number 97-B-01 (With Scrivener's Order Dated July 2, 1997).
Appendix C, Common Conditions.
Appendix CAM, Compliance Assurance Monitoring Plan.
Appendix Hg CEMS - Quality Assurance Plan.
Appendix I, List of Insignificant Emissions Units and/or Activities.
Appendix 40 CFR 60, Subpart A - General Provisions.
Appendix 40 CFR 60, Subpart Da.
Appendix 40 CFR 60, Subpart Y.
Appendix 40 CFR 60, Subpart OOO.
Appendix NGS, CT Heat Input Nominal Values: Heat Load MW vs. Temperature.
Appendix O&M, Operation and Maintenance Plan under RACT for PM.
Appendix Q: Protocol for Startup and Shutdown.
Appendix RR, Facility-wide Reporting Requirements.
Appendix SJRPP, Table 6 (Revised): Parts A and B.
Appendix TR, Facility-wide Testing Requirements.
Appendix TV, Title V General Conditions.
Appendix U, List of Unregulated Emissions Units and/or Activities.

APPENDIX A

ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION NUMBERS

Abbreviations and Acronyms:

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

AOR: Annual Operating Report

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DARM: Division of Air Resources Management

DCA: Department of Community Affairs

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

ISO: International Standards Organization (refers to those conditions at 288 Kelvin, 60% relative humidity and 101.3 kilopascals pressure.)

kPa: kilopascals

LAT: Latitude

lb: pound

lbs/hr: pounds per hour

LONG: Longitude

MACT: maximum achievable technology

mm: millimeter

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

ORIS: Office of Regulatory Information Systems

OS: Organic Solvent

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of significant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

RMP: Risk Management Plan

RO: Responsible Official

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SOA: Specific Operating Agreement

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

x: By or times

Citations:

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, guidance memorandums, permit numbers and ID numbers.

Code of Federal Regulations:

Example: **[40 CFR 60.334]**

Where:	40	refers to	Title 40
	CFR	refers to	Code of Federal Regulations
	60	refers to	Part 60
	60.334	refers to	Regulation 60.334

Florida Administrative Code (F.A.C.) Rules:

Example: **[Rule 62-213.205, F.A.C.]**

Where:	62	refers to	Title 62
	62-213	refers to	Chapter 62-213
	62-213.205	refers to	Rule 62-213.205, F.A.C.

Identification Numbers:

Facility Identification (ID) Number:

Example: Facility ID No.: 1050221

Where:

105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by state database.

Permit Numbers:

Example: 1050221-002-AV, or
1050221-001-AC

Where:

AC = Air Construction Permit
AV = Air Operation Permit (Title V Source)
105 = 3-digit number code identifying the facility is located in Polk County
0221= 4-digit number assigned by permit tracking database
001 or 002= 3-digit sequential project number assigned by permit tracking database

Example: PSD-FL-185
PA95-01
AC53-208321

Where:

PSD = Prevention of Significant Deterioration Permit
PA = Power Plant Siting Act Permit
AC53 = old Air Construction Permit numbering identifying the facility is located in Polk County

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	
	)	
Florida Electric Power Coordinating Group, Inc.,	)	ASP No. 97-B-01
	)	
Petitioner.	)	

ORDER ON REQUEST
FOR
ALTERNATE PROCEDURES AND REQUIREMENTS

Pursuant to Rule 62-297.620, Florida Administrative Code (F.A.C.), the Florida Electric Coordinating Group, Incorporated, (FCG) petitioned for approval to: (1) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test; and, (2) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test during the year prior to renewal of an operation permit. This Order is intended to clarify particulate testing requirements for those fossil fuel steam generators which primarily burn gaseous fuels including, but not necessarily limited to natural gas.

Having considered the provisions of Rule 62-296.405(1), F.A.C., Rule 62-297.310(7), F.A.C., and all supporting documentation, the following Findings of Fact, Conclusions of Law, and Order are entered:

FINDINGS OF FACT

1. The Florida Electric Power Coordinating Group, Incorporated, petitioned the Department to exempt those fossil fuel steam generators which have a heat input of more than 250 million Btu per hour and burn solid and/or liquid fuel less than 400 hours during the year from the requirement to conduct an annual particulate matter compliance test. [Exhibit 1]

2. Rule 62-296.405(1)(a), F.A.C., applies to those fossil fuel steam generators that are not subject to the federal standards of performance for new stationary sources (NSPS) in 40 CFR 60 and which have a heat input of more than 250 million Btu per hour.

3. Rule 62-296.405(1)(a), F.A.C., limits visible emissions from affected fossil fuel steam generators to, "20 percent opacity except for either one six-minute period per hour during which

not exceed 40 percent. The option selected shall be specified in the emissions unit's construction and operation permits. Emissions units governed by this visible emission limit shall test for particulate emission compliance annually and as otherwise required by Rule 62-297, F.A.C."

4. Rule 62-296.405(1)(a), F.A.C., further states, "Emissions units electing to test for particulate matter emission compliance quarterly shall be allowed visible emissions of 40 percent opacity. The results of such tests shall be submitted to the Department. Upon demonstration that the particulate standard has been regularly complied with, the Secretary, upon petition by the applicant, shall reduce the frequency of particulate testing to no less than once annually.

5. Rule 297.310(7)(a)1., F.A.C., states, "The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit."

6. Rule 297.310(7)(a)3., F.A.C., states, "The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision.

7. Rule 297.310(7)(a)3., F.A.C., further states, "In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal: a. Did not operate; or, b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours."

8. Rule 297.310(7)(a)4., F.A.C., states, "During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for: a. Visible emissions, if there is an applicable standard; b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant..."

9. Rule 297.310(7)(a)5., F.A.C., states, "An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours."

10. Rule 297.310(7)(a)6., F.A.C., states, "For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be

required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup."

11. Rule 297.310(7)(a)7., F.A.C., states, "For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup." [Note: The reference should be to Rule 62-296.405(1)(a), F.A.C., rather than Rule 62-296.405(2)(a), F.A.C.]

12. The fifth edition of the U. S. Environmental Protection Agency's Compilation of Air Pollutant Emission Factors, AP-42, that emissions of filterable particulate from gas-fired fossil fuel steam generators with a heat input of more than about 10 million Btu per hour may be expected to range from 0.001 to 0.006 pound per million Btu. [Exhibit 2]

13. Rule 62-296.405(1)(b), F.A.C. and the federal standards of performance for new stationary sources in 40 CFR 60.42, Subpart D, limit particulate emissions from uncontrolled fossil fuel fired steam generators with a heat input of more than 250 million Btu to 0.1 pound per million Btu.

CONCLUSIONS OF LAW

1. The Department has jurisdiction to consider the matter pursuant to Section 403.061, Florida Statutes (F.S.), and Rule 62-297.620, F.A.C.

2. Pursuant to Rule 62-297.310(7), F.A.C., the Department may require Petitioner to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

3. There is reason to believe that a fossil fuel steam generator which does not burn liquid and/or solid fuel (other than during startup) for a total of more than 400 hours in a federal fiscal year and complies with all other applicable limits and permit conditions is in compliance with the applicable particulate mass emission limiting standard.

ORDER

Having considered the requirements of Rule 62-296.405, F.A.C., Rule 62-297.310, F.A.C., and supporting documentation, it is hereby ordered that:

1. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours;

2. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup;

3. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(1)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup;

4. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

5. Pursuant to Rule 62-297.310(7), F.A.C., owners of affected fossil fuel steam generators may be required to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

6. Pursuant to Rule 62-297.310(8), F.A.C., owners of affected fossil fuel steam generators shall submit the compliance test report to the District Director of the Department district office having jurisdiction over the emissions unit and, where applicable, the Air Program Administrator of the appropriate Department-approved local air program within 45 days of completion of the test.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 of the Florida Statutes, or a party requests mediation as an alternative remedy under section 120.573 before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed decision may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions must be filed within 21 days of receipt of this Order. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department File Number, and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by each petitioner, if any;

(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement identifying the rules or statutes each petitioner contends require reversal or modification of the Department's action or proposed action; and,

(g) A statement of the relief sought by each petitioner, stating precisely the action each petitioner wants the Department to take with respect to the Department's action or proposed action in the notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information:

(a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any;

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

(d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following:

(a) The names, addresses, and telephone numbers of any persons who may attend the mediation;

(b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

(c) The agreed allocation of the costs and fees associated with the mediation;

(d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

(e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

(f) The name of each party's representative who shall have authority to settle or recommend settlement; and

(g) The signatures of all parties or their authorized representatives.

As provided in section 120.573 of the Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by sections 120.569 and 120.57 for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under section 120.542 of the Florida Statutes. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;

(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;

(c) Each rule or portion of a rule from which a variance or waiver is requested;

(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;

(e) The type of action requested;

(f) The specific facts that would justify a variance or waiver for the petitioner;

(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and

(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver, when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 17 day of March, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

—Page 8 of 8—

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a copy of the foregoing was mailed to Rich Piper, Chair, Florida Power Coordinating Group, Inc., 405 Reo Street, Suite 100, Tampa, Florida 33609-1004, on this 18th day of March 1997.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Martha Wise 3-18-97
Clerk Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	
	)	
Florida Electric Power Coordinating Group, Inc.,	)	ASP No. 97-B-01
	)	
Petitioner.	)	

ORDER CORRECTING SCRIVENER'S ERROR

The Order which authorizes owners of natural gas fired fossil fuel steam generators to forgo particulate matter compliance testing on an annual basis and prior to renewal of an operation permit entered on the 17th day of March, 1997, is hereby corrected on page 4, paragraph number 4, by deleting the words "pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.":

4. In renewing an air operation permit ~~pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.,~~ the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

DONE AND ORDERED this 2 day of July, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

The above two documents comprise Appendix ASP, ASP Number 97-B-01 (With Scrivener's Order Dated July 2, 1997).

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
4. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
5. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
6. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

7. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
8. Emissions Computation and Reporting:
   a. *Applicability.* This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit. [Rule 62-210.370(1), F.A.C.]
   b. *Computation of Emissions.* For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.
      (1) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of

any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.

(a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.

(b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(2) Continuous Emissions Monitoring System (CEMS).

(a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

1) A calibrated flow meter that records data on a continuous basis, if available; or

2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(c) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

(3) Mass Balance Calculations.

(a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

(4) Emission Factors.

a. An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

b. If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

(8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(2), F.A.C.]

c. *Annual Operating Report for Air Pollutant Emitting Facility*

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

a. All Title V sources.

b. All synthetic non-Title V sources.

c. All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

d. All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by April 1 of the following year. If the report is submitted using the Department's electronic annual operating report software, there is no requirement to submit a copy to any DEP or local air program office.

(4) Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

(5) Facility Relocation. Unless otherwise provided by rule or more stringent permit condition, the owner or operator of a relocatable facility must submit a Facility Relocation Notification Form (DEP Form No. 62-210.900(6)) to the Department at least 30 days prior to the relocation. A separate form shall be submitted for each facility in the case of the relocation of multiple facilities which are jointly owned or operated.

[Rule 62-210.370(3), F.A.C.]

COMPLIANCE ASSURANCE MONITORING (version dated 06/09/2005)

Compliance Assurance Monitoring Requirements

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1. – 17. are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables, as submitted by the applicant and approved by the Department.

40 CFR 64.6 Approval of Monitoring.

1. The attached CAM plan(s), as submitted by the applicant, is/are approved for the purposes of satisfying the requirements of 40 CFR 64.3.
[40 CFR 64.6(a)]

2. The attached CAM plan(s) include the following information:
(i) The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
(ii) The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and
(iii) The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.
[40 CFR 64.6(c)(1)]

3. The attached CAM plan(s) describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see **CAM Conditions 5. - 14.**) and reporting exceedances or excursions (see **CAM Conditions 15. – 16.**).
[40 CFR 64.6(c)(2)]

4. The permittee is required to conduct the monitoring specified in the attached CAM plan(s) and shall fulfill the obligations specified in the conditions below (see **CAM Conditions 5. - 16.**).
[40 CFR 64.6(c)(3)]

40 CFR 64.7 Operation of Approved Monitoring.

5. Commencement of operation. The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit.
[40 CFR 64.7(a)]

6. Proper maintenance. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 CFR 64.7(b)]

7. Continued operation. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and

required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 CFR 64.7(c)]

8. Response to excursions or exceedances.

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) & (2)]

9. Documentation of need for improved monitoring. If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements.

10. Based on the results of a determination made under **CAM Condition 8.b.**, above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with **CAM Condition 4.**, an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other

criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.
[40 CFR 64.8(a)]

11. Elements of a QIP:

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(i) Improved preventive maintenance practices.
(ii) Process operation changes.
(iii) Appropriate improvements to control methods.
(iv) Other steps appropriate to correct control performance.
(v) More frequent or improved monitoring (only in conjunction with one or more steps under **CAM Condition 11.b(i)** through **(iv)**, above).

[40 CFR 64.8(b)]

12. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.
[40 CFR 64.8(c)]

13. Following implementation of a QIP, upon any subsequent determination pursuant to **CAM Condition 8.b.**, the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems; or

b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

[40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.
[40 CFR 64.8(e)]

<u>40 CFR 64.9 Reporting And Recordkeeping Requirements.</u>

15. General reporting requirements.

a. *Commencing from the effective date of this permit, the owner or operator shall submit* monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.

b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:

(i) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(ii) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(iii) A description of the actions taken to implement a QIP during the reporting period as specified in **CAM Conditions 10.** through **14.** Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 CFR 64.9(a)]

16. General recordkeeping requirements.

a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to **CAM Conditions 10.** through **14.** and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[40 CFR 64.9(b)]

40 CFR 64.10 Savings Provisions.

17. It should be noted that nothing in this appendix shall:

a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

[40 CFR 64.10

COMPLIANCE ASSURANCE MONITORING (version dated 06/09/2005)

The following emissions units are subject to the CAM provisions only for the pollutants indicated:

E.U. ID No.	***Brief Description***	*Pollutant(s) subject to CAM*
-026 & -027	NGS Circulating Fluidized Bed Boiler Nos. 2 & 1	PM
-016 & -017	SJRPP Boiler Nos. 1 & 2	PM

For ease of reference the following definitions are cited from 40 CFR 64.1 Definitions (10/03/1997):

> *Exceedance shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.*
>
> *Excursion shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring.*

E.U. ID No.	Brief Description
-026 & -027	NGS Circulating Fluidized Bed Boiler Nos. 2 & 1

2,764 MMBtu/Hr Coal And Petroleum Coke-Fired Boilers
Particulate Matter Emissions Controlled By Baghouses

Monitoring Approach and Corrective Action Procedures

Table 1. *Monitoring Approach*

	Compliance Indicator
I. Indicator	Stack opacity
Measurement Approach	Continuous opacity monitoring system (COMS)
II. Indicator Range	An excursion is defined as 5 consecutive 6-minute averages of opacity greater than 6.0%.
III. Performance Criteria A. Data Representativeness	Based on available data under normal operation, the representative stack opacity of each unit is < 5 %. A 50% average opacity above 5% during non-startup or shutdown periods is atypical and may indicate a potential problem with the baghouse.
B. Verification of Operational Status	Annual testing during normal operation is used to calibrate the opacity monitor and determine the opacity and verify particulate mass loading.
C. QA/QC Practices and Criteria	Install and operate COMS according to 40 CFR Appendix B, Performance Specification 1 and general provisions 60.13.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	The COMS collects data that are reduced to 6-minute averages. (5 consecutive 6-minute averages greater than 6.0% indicate an excursion)
F. Averaging Period	6 minutes.

Table 2. Corrective Action Procedures Summary

	Description
IV. Initiation of Corrective Action Procedures	Corrective action shall be initiated with the discovery of 5 consecutive 6-minute averages of opacity greater than the opacity that defines an excursion (as defined in Table 1.). The plant staff that made the discovery shall immediately notify the shift supervisor or responsible official. This action describes a corrective action trigger.
V. Time of Completion of Corrective Action Procedures	As soon as practically possible.
VI. Corrective Action	The shift supervisor or responsible official will implement the following as a corrective action. Procedures as described in the Fabric Filter Bag Inspection and Diagnostic Procedures (FFBIDP) as presented in the Operations and Maintenance Plan (O&M Plan) includes the following alternatives that will be initiated as necessary. • Perform operational diagnostics to identify cause of the excursion. • If operational diagnostics indicate the failure of a bag(s), the failed bag will be identified and the reason for failure will be identified. • If isolation of the compartment can be accomplished to reduce opacity below the excursion, such measures will be undertaken. • In the event of the need for bag replacement, the task will be undertaken based on procedures described in the O&M Plan for the facility. Regardless of the failure mechanism, baghouse operation will be restored such that the cause of excursion is identified and appropriate actions taken to ensure opacity below excursion levels.

E.U. ID No.	Brief Description
-016 & -017	SJRPP Boiler Nos. 1 & 2

6,144 MMBtu/Hr Coal And Petroleum Coke-Fired Boilers
Particulate Matter Emissions Controlled By ESP

Monitoring Approach and Corrective Action Procedures

Table 3. Monitoring Approach

	Compliance Indicator
I. Indicator	Duct opacity.
Measurement Approach	Continuous opacity monitoring system (COMS).
II. Indicator Range	An excursion is defined as any 1-hour block average of opacity greater than 18% (other than startup and shutdown periods).
III. Performance Criteria	
A. Data Representativeness	Based on available data under normal operation, the representative stack opacity of each unit is in the range of 5 to 15%. In addition, the COMS are located upstream of the scrubber and as such; the opacity at the stack exit is lower than the value indicated by the COMS. Therefore, 18% opacity during non-startup or shutdown periods is atypical and may indicate a potential problem with the ESP.
B. Verification of Operational Status	Annual testing during normal operation is used to calibrate the opacity monitor and determine the opacity and verify particulate mass loading.
C. QA/QC Practices and Criteria	Install and operate COMS according to 40 CFR Part 60 Appendix B, Performance Specification 1 and general provisions 60.13.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	The COMS collects data that are reduced to 6-minute averages and the 1-hour block average is calculated based on the 6-minute averages.
F. Averaging Period	One hour.

Table 4. Corrective Action Procedures Summary

		Description
IV.	Initiation of Corrective Action Procedures	Corrective action shall be initiated with the discovery of a one-hour block average of opacity greater than 18% and that defines an excursion (as defined in Table 3.). The plant staff that made the discovery shall immediately notify the shift Manager or responsible official. This action describes a corrective action trigger.
V.	Time of Completion of Corrective Action Procedures	As soon as practically possible.
VI.	Corrective Action	The shift Manager or responsible official will implement the following as a corrective action. Procedures, as presented in the O&M Plan, include the following alternatives that will be initiated as necessary. • Perform operational diagnostics to identify cause of the excursion. • If operational diagnostics indicate a malfunction of the ESP, the reason for failure will be identified. • In the event of the need for the unit shutdown to bring opacity to below excursion levels, the task will be undertaken based on procedures described in the O&M Plan for the facility. Regardless of the failure mechanism, ESP operation will be restored such that the cause of excursion is identified and appropriate actions taken to ensure opacity below excursion levels.

APPENDIX Hg CEMS

QUALITY ASSURANCE PLAN

See Quality Assurance Plan - JEA Northside Hg CEMS version 2.0

Mercury CEMS Quality Assurance Plan

JEA

Northside Generating Station

Units 1 and 2

Jacksonville, Florida

ORIS: 000667

Revision Number: 2.0

TABLE OF CONTENTS

REVISION NOTES

Revision No.	Revision Date	Revised Sections	Notes
Draft	July 2008	NA	Draft
1.0	Dec 2008	All	Revised to accurately reflect JEA Northside Systems
1.1	Feb 2009	All	Revised to reflect feedback from FDEP. 7 day drift added, annual RATA added
2.0	Nov 2010	All	Revised in response to request from DEP

Chapter 1.0 Quality Assurance Plan Overview

1.1 Introduction

This Quality Assurance Plan (QAP) is designed to provide guidance and support in the operation and maintenance of the Thermo Fisher Scientific (Thermo) Mercury Freedom^{TM} System installed at the JEA Northside Generating Station (NGS), Jacksonville, FL. This document consists of a description of the QAP, the organizational structure that will implement to support the plan, and the procedures for carrying out the plan. This QAP must be used along with the following documents. Those included in the Appendices are noted in parenthesis.

- Northside Generating Station, CEMS/COMS Quality Assurance Plan, specifically the Flow Monitoring and Data Acquisition and Handling System sections, which are utilized by the these Mercury CEMS
- Thermo Mercury Freedom^{TM} System Operation and Maintenance Manuals, including:
    - *Model 80i Hg Analyzer Instruction Manual 103194-00*
    - *Model 81i Hg Calibrator Instruction Manual 103068-00*
    - *Model 82i Hg Probe Controller Instruction Manual 103519-00*
    - *Model 82X Fiber Optic Probe Controller Instruction Manual 105464-00*
    - *Model 83i Extraction Probe Instruction Manual 101187-00*
    - *Model 83i GC Hg Non-Inertial Dilution Probe Instruction Manual 101187-00*
    - *Mercuric Chloride Generator Instruction Manual 105648-00*
    - *Mercury System Manual 105648-00*
- Mercury Freedom^{TM} System Recommended Spare Parts (Appendix AA)

The NGS is located at 4377 Heckscher Drive, Duval County, Jacksonville, FL and is within the jurisdiction of USEPA Region 4 and the Florida Department of Environmental Protection (FDEP). The Northside Generating Station Units 1 and 2 are coal and petroleum coke-fired circulating fluidized bed (CFB) boilers, each rated at 2764 mmBtu/hr heat input and 325 MW electrical output. Unit 3 is oil and pipeline natural gas fired dry-bottom boiler, rated at 5290 mmBtu/hr heat input and 540 MW electrical output.

1.2 Quality Assurance Policy

It is the policy of JEA to adhere to all applicable rules and regulations. All necessary air emission data will be obtained in order to demonstrate compliance with data quality objectives. This Hg QAP establishes operational procedures that will ensure data and measurements are accurate and precise. At no time will non-quality assured data be reported as valid data.

1.3 Definitions

In specific terms relating to the CEM systems, "Quality Control" refers to the specific procedures performed regularly (e.g., daily calibration checks, routine filter replacements or quarterly calibration error tests to ensure CEM data is of high quality. "Quality Assurance" is defined as a management program designed to ensure that QC activities are being performed.

Following is a general list of terms and acronyms used in this Quality Assurance and Quality Control Plan and the CEMS/COMS Quality Assurance Plan.

Acid Rain Program (ARP) - the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with Title IV of the Clean Air Act, November 15, 1990.

Administrator (when used in the regulatory definitions of this QA/QC Manual) – the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Alternate designated representative (ADR) - a responsible person authorized by the owners and operators of an affected source, as evidenced by a certificate of representation, submitted in accordance with Subpart B of the Acid Rain Program, to act on behalf of the designated representative in matters pertaining to the Acid Rain Program.

As-fired - the taking of a fuel sample just prior to its introduction into the unit for combustion.

Calibration error - the difference between:

(1) The response of a gaseous monitor to a calibration gas and the known concentration of the calibration gas;

(2) The response of a flow monitor to a reference signal and the known value of the reference signal.

Calibration error is calculated as:

$$CE = \frac{|R - A|}{S} \times 100$$

where,
CE = Calibration Error
R = Reference Value
A = Actual CEMS Response
S = CEMS Span Value

Calibration gas: (1) a standard reference material; (2) a NIST traceable reference material; (3) a Protocol 1 gas; (4) a research gas material; or (5) zero air material

Capacity factor - the ratio of a unit's actual annual electric output (expressed in MWe-hr) to the unit's nameplate capacity times 8760 hours, or the ratio of a unit's annual heat input (in mmBtu) to the unit's maximum design heat input times 8760 hours.

Commence commercial operation - to have begun to generate electricity for sale, including the sale of test generation.

Commence construction - that an owner or operator has either undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Common Stack - the exhaust of emissions from two or more units through a single flue.

Continuous emissions monitoring system (CEMS) - the equipment used to sample, analyze, measure, and provide a permanent record of emissions. Emission readings are taken at least once every 15 minutes. For mercury the measurement is micrograms per dry standard cubic meter (ug/m^3). The following systems are component parts included in the JEA Unit 1 & 2 Northside Generating Station continuous emissions monitoring system. (NOTE: only the Mercury CEMS are addressed in this QAP.):

(1) Mercury concentration monitors;

(2) Sulfur dioxide pollutant concentration monitor;

(3) Flow monitor;

(4) Nitrogen oxides pollutant concentration monitors;

(5) Diluent gas monitor (at Northside Generating Station Units 1 - 3, the diluent gas is CO_2); and

(6) A data acquisition and handling system (DAHS).

DAHS (Data Acquisition and Handling System) - For the CEMS at Northside Generating Station, this refers to the Microsoft Windows™-based computer system by Babcock & Wilcox (B&W).

Designated Representative (DR) - a responsible person authorized by the owners and operators of an affected source and of all units at the source or by the owners and operators of a combustion source or process source, as evidenced by a certificate of representation, submitted in accordance with Subpart B of the Acid Rain Program, to represent and legally bind each owner and operator, as a matter of federal law, in matters pertaining to the Acid Rain Program. The DR at Northside Generating Station is the Senior Vice President - Generation.

Diluent gas - a major gaseous constituent in a gaseous pollutant mixture, which in the case of emissions from fossil fuel-fired units are carbon dioxide and oxygen. At Northside Generating Station, the diluent gas is carbon dioxide (CO_2).

Gaseous fuel - a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat.

Gas-fired:

1) The combustion of:
   a) Natural gas or other gaseous fuel (including coal-derived gaseous fuel), for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and
   b) Any fuel other than coal or coal-derived fuel (except for coal-derived gaseous fuel) for the remaining heat input, if any; provided that for purposes of 40 CFR Part 75, any fuel used other than natural gas, shall be limited to:
      i) Gaseous fuels containing no more sulfur than natural gas; or
      ii) Fuel oil.
2) For purposes of 40 CFR Part 75, a unit may initially qualify as gas-fired under the following circumstances:
   a) If the designated representative provides fuel usage data for the unit for the three calendar years immediately prior to submission of the monitoring plan, and if the unit's fuel usage is projected to change on or before January 1, 1995, the Designated Representative submits a demonstration satisfactory to the EPA Administrator that the unit will qualify as gas-fired under the first sentence of this definition using the years 1995 through 1997 as the three calendar year period; or
   b) If a unit does not have fuel usage data for one or more of the three calendar years immediately prior to submission of the monitoring plan, the designated representative submits:
      i) The unit's designed fuel usage;
      ii) Any fuel usage data, beginning with the unit's first calendar year of commercial operation following 1992;
      iii) The unit's projected fuel usage for any remaining future period needed to provide fuel usage data for three consecutive calendar years; and
      iv) Demonstration satisfactory to the Administrator that the unit will qualify as gas-fired under the first sentence of this definition using those three consecutive calendar years as the three calendar year period.

Missing data period - the total number of consecutive hours during which any component part of a certified CEMS is not providing quality-assured data, regardless of the reason.

Natural gas - a naturally-occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 1.0 grain or less of hydrogen sulfide per 100 standard cubic feet and the hydrogen sulfide constitutes more than 50% (by weight) of the total sulfur in the gas fuel. Additionally, natural gas must meet either be composed of at least 70% methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.

Out-of-control period - any period:

(1) Beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit, such as a relative accuracy test audit, that indicates that the instrument is not measuring and recording within the applicable performance specifications; and

(2) Ending with the hour corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Pipeline natural gas - Pipeline natural gas means natural gas that is provided by a supplier through a pipeline and that contains 0.3 grains or less of hydrogen sulfide per 100 standard cubic feet and the hydrogen sulfide in content of the gas constitutes at least 50% (by weight) of the total sulfur in the fuel.

Protocol 1 gas - a calibration gas mixture prepared and analyzed according to the "Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Emission Monitors

Quality Control (QC) - the procedures, policies, and corrective actions necessary to ensure data quality. QC procedures are typically routine, scheduled activities including daily, weekly, quarterly, semi-annual, and annual checks and inspections designed to optimize CEMS performance and reliability.

Quality Assurance (QA) - the independent checks performed to ensure that the quality control procedures are functioning as designed. QA procedures are external checks performed by individuals that are not normally involved with QC and maintenance operations. For these CEMS systems, QA checks are performed based on a schedule specified in this plan. These procedures are also performed on an as-needed basis. The resulting quality assurance assessments may activate QC measures and corrective actions if necessary. If corrective actions are taken, the quality assurance procedure is repeated.

Reference value or reference signal - the known concentration of a calibration gas, the known value of an electronic calibration signal, or the known value of any other measurement signal, assumed to be the true value for the pollutant or diluent concentration or volumetric flow being measured.

Relative accuracy - a statistic designed to provide a measure of the systematic and random errors associated with data from continuous emission monitoring systems, and is expressed as the absolute mean difference between the pollutant concentration or volumetric flow measured by the pollutant concentration or flow monitor and the value determined by the applicable reference method(s) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests.

Standard conditions - 68°F at 1 atmosphere (29.92 inches of mercury).

Substitute data - emissions or volumetric flow data provided to assure 100 percent recording and reporting of emissions when all or part of the continuous emission monitoring system is not functional or is operating outside applicable performance specifications.

Unit - a fossil fuel-fired combustion device.

Unit operating hour - any hour (or fraction of an hour) during which a unit combusts any fuel.

Zero air material - either:

(1) a calibration gas certified by the gas vendor not to contain concentrations of either SO_2, NO_X, or total hydrocarbons above 0.1 parts per million (ppm); a concentration of CO above 1 ppm; and a concentration of CO_2 above 400 ppm, or

(2) ambient air conditioned and purified by a continuous emissions monitoring system for which the CEMS vendor certifies that the particular model produces conditioned gas that either does not contain concentrations of either SO_2, NO_X, or total hydrocarbons above 0.1 ppm or CO_2 above 400 ppm; and that does not contain concentrations of other gases that interfere with instrument readings or cause the instrument to read concentrations of SO_2, NO_X, or CO_2 for a particular CEMS model.

1.4 Objective

The objective of the QAP is to establish a series of Quality Assurance (QA) and Quality Control (QC) activities that will provide a high level of confidence in the data reported by the CEMS. Quality Control is considered the procedures, policies, and corrective actions necessary to ensure data quality. QC procedures are typically routine, scheduled activities including daily, weekly, quarterly, semi-annual, and annual checks and inspections designed to optimize CEMS performance and reliability. Quality Assurance is defined as the independent checks performed to ensure that the quality control procedures are functioning as designed. QA procedures are external checks performed by individuals that are not normally involved with QC and maintenance operations. If corrective actions are taken, the quality assurance procedure is repeated.

The QAP provides guidelines for implementing QA and QC activities. This document is intended to provide both the foundation for the establishment and maintenance of the QA/QC plan as well as a guidance document for the day-to-day operation of the CEMS. It is intended to be an integral and dynamic part of the QA/QC program. It shall continually reflect the current state of the program as it is actually implemented at the facility. It has been designed for easy updating and modification as the program grows and changes over time. It is only by making this a "living," changing document that a truly effective QA/QC plan can be maintained.

1.5 How to Use This Plan

This Plan is intended to be used in several ways.

- Internal Use: To provide direction and guidance in the operation and maintenance of the CEM systems.
- Regulatory Agency Use: To meet the requirements and to demonstrate to regulatory personnel that a comprehensive QA/QC Plan is being implemented at the facility.
- CEM Vendor Use: FOR ON-SITE REVIEW ONLY. To determine what procedures are in use if a vendor is required to diagnose or repair system problems.

- Training: To provide new employees with a source of comprehensive information and step-by-step procedures for system operations and maintenance. This reduces the "learning curve" for new employees.

1.5.1 Scope of Quality Assurance Plan

In order to comply with the vacated CAMR rules (see Important Note in Section 1.1), JEA has installed two Mercury Freedom™ System CEMS at Units 1 and 2 at the NGS.

The Mercury Freedom™ System is comprised of:

- Hg analyzer (Model 80i)
- Hg calibrator (Model 81i)
- Hg probe controller (Model 82i)
- High temperature, dilution-based probe (Model 83i) and
- Zero air supply
- Chlorine (Cl_2)

The Hg CEMS are connected to a central Data Acquisition and Handling System (DAHS) and Flow Monitoring System, which are presented in the NGS CEMS/COMS QAP.

1.5.2 Quality Assurance Procedures

QA procedures consist of a series of checks and audits that are performed on the CEMS on a predetermined, as well as an "as needed", basis. The resulting assessments activate QC measures and corrective actions. After the corrective actions are performed, the data quality is again assessed. The quality of the data will determine whether the corrective actions were successful or whether further actions are required.

The following is a brief description of the type and frequency of QA/QC procedures.

QC procedures are specific maintenance activities necessary to optimize the CEMS performance and reliability. These activities include daily, weekly, quarterly, semi-annual, and annual checks and inspections (Refer to Table 1-1). Corrective actions, such as corrective maintenance and recalibrations, are performed when needed.

Table 1-1: Summary of QA and QC procedures in this Quality Assurance Plan

Frequency	Test
Daily	Calibration Error (CE) test
	Daily CEMS Checklist
	Data Review and Validation
Weekly	System Integrity Check (single-level) - if daily CE is elemental only
	Preventative Maintenance: Analyzer Checks
Quarterly	System Integrity Check (oxidized)
	Linearity Check (3-level)
	Preventative Maintenance: Analyzer Checks
Semiannual / Annual	RATA- Annually
	Preventative Maintenance: Analyzer Checks

1. Daily Assessments
   a. Two-point (Zero and Span) calibration error tests for Hg monitors must fall within 5.0% of the span value. The calibration error test can be done using either elemental or oxidized Hg standards.
   b. If an Out-of-control event occurs as due to failure of the daily assessment, the appropriate maintenance and corrective action(s) will be performed and the daily assessment repeated for the affected monitor.
   c. Data recording and tabulation of all calibration error tests according to month, day, and magnitude.
2. Weekly Assessments
   a. Weekly system integrity check for Hg monitors using oxidized mercury to check converter efficiency.
3. Quarterly Assessments
   a. Quarterly three-point linearity check for Hg monitors must fall within 10.0% of the reference value. The linearity check must be done using elemental Hg standards.
   b. If an Out-of-control event occurs due to failure of the quarterly assessment, the appropriate maintenance and corrective action(s) will be performed and the quarter assessment repeated for the affected monitor.
4. Annual QA Activities
   a. An annual RATA will be performed following current industry standards and regulatory practices.

1.6 Document Control

To ensure that all copies of the QAP are revised to contain current procedures, the following document control headers and footers are provided on each page:

- Revision Number
- Date of Revision
- Section/Page Number

This QAP is an important regulatory document. As a result, strict document controls are required. ***Do not copy this QA/QC Plan.*** Unauthorized copies cannot be updated.

1.6.1 Responsible Individuals

The Environmental Services Coordinator shall be responsible for ensuring this QAP remains current and complete. The Environmental Services Coordinator will also be responsible for compiling the Document History in Section 1.5.5 of this Plan. The Manager of Instrumentation & Controls shall serve as an alternate and shall remain familiar with this QAP as well as all environmental policies and procedures. Copies of this QAP shall be maintained in the following locations:

LOCATION
1. Plant I&C Shop
2. CEMS Shelter
3. Environmental Services Coordinator's Office

The Environmental Services Coordinator may designate other locations for this QAP as needed.

1.6.2 Revisions

Only the Environmental Services Coordinator is authorized to revise this document. Errors or omissions should be pointed out to the Environmental Services Coordinator to ensure this document remains accurate and complete. The Environmental Services Coordinator will distribute updates to ensure these documents remain consistent. The Environmental Services Coordinator will also archive the outdated versions of this Plan for reference. At least once each year the Environmental Services Coordinator, Maintenance Manager, I&C Technicians and Operations Supervisor shall meet to review QA/QC procedures. This meeting shall take place during the second quarter each calendar year.

It is important that all owners of this document have the most recently revised information and that outdated information is discarded. When the document owner receives the update, he/she should remove the old section, initial it, and return it to the Environmental Technician within five (5) days. This acknowledges receipt of the replacements. If the old section(s) is not received within five (5) days, the Environmental Technician w ill follow-up until the old section(s) is returned.

1.6.3 QA/QC Plan Forms

Listed below are the specific forms to be used when completing the QA/QC procedures. These forms must be used to document the completion of the QA and QC procedures identified in this Plan.

1. DAILY PREVENTATIVE MAINTENANCE CHECKLIST (Example Form 7-1)
2. QUARTERLY PREVENTATIVE MAINTENANCE CHECKLIST (Example Form 7-2)
3. SEMI_ANNUAL PREVENTATIVE MAINTENANCE CHECKLIST (Example Form 7-3)
4. ANNUAL PREVENTATIVE MAINTENANCE CHECKLIST (Example Form 7-4)
5. LONG TERM STORAGE (Example Form 7-5)
6. CORRECTIVE ACTION REPORT (Example Form 7-6)

1.6.4 Instrument User's Manuals

The Mercury Freedom^{TM} Systems are supplied from the manufacturer with the User's Manuals. These manuals are an important part of this QAP and should be used in conjunction with this Plan whenever servicing or troubleshooting the CEMS system. The Environmental Services Coordinator shall be responsible for ensuring that these User's Manuals are kept current.

These manuals should be kept in the Plant Library and the Maintenance Office for reference. Copies of these manuals may be removed from these locations for short periods, but should be returned before leaving the plant for the day.

1.7 Data Recording and Reporting

Air emissions reports will be submitted to the Florida Department of Environmental Quality, Air Quality Division, and EPA on an as required basis. The contents of the reports will be specified in the air operating permit.

These may include the following:

All required hourly data must be recorded electronically and not be manually edited. This includes all CEM data. This data can be recorded through different DAHS components and combined at the end of the quarter. The owner/operator must provide State auditors real time access to this data. Other data, including sampling results, default rates, hourly load data, hourly operating status and long-term fuel measurement data may be recorded electronically or entered manually into the DAHS.

A central CEMS file is maintained in the Environmental Office and the CEMS Shelter. The file contains QAP check forms, audit results, corrective action forms, and calibration gas certificates of analysis. This central file also serves as an archive for all CEM records including logbooks, daily data summaries, agency correspondence, applicable permits, emissions reports, maintenance request forms, and strip charts (as applicable).

The CEMS data acquisition and reporting is controlled by a central Data Acquisition and Handling System (DAHS). The DAHS provides automated data monitoring and management capabilities to the CEMS using B&W NETDAHS software on a Microsoft Windows platform.

The CEMS has a Programmable Logic Controller (PLC) that transmits data from the analyzer to the central DAHS. The DAHS polls the PLC every ten (10) seconds for data to generate and store one (1) minute averages. The DAHS will indicate any occurrence of specification limit excedances or CEM operational problems. In the DAHS, necessary reports are generated in the required format for submittal to the applicable regulatory agencies.

All information reported to EPA Region 4 is maintained on file for a minimum of three years.

1.8 Data Capture Requirements

The CEMS must be capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. Emissions concentrations collected by the monitors will be reduced to hourly averages. Hourly averages will consist of at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour.

An hourly average may be computed from two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable due to performance of a calibration, quality assurance, or preventive maintenance activities. All valid measurements or data points collected during an hour will be used to calculate hourly averages. All data points collected during an hour will be, to the extent practicable, evenly spaced over the hour.

Failure to acquire the minimum number of data points for calculation of an hourly average will result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour.

If a valid hour of data is not obtained, the owner/operator will report that the mercury instrument was out of service and detail the events in a monthly report that lists instrument downtime with an availability report.

1.9 Quality Assurance Status

A monitor is considered out-of-control starting with the hour of the failure of any quality assurance test. A test that is initiated and discontinued because the monitoring system is failing to meet the applicable performance specification or is otherwise found to be out-of-control is considered a failed test and the monitoring system is considered out-of-control starting with the hour in which the test was discontinued.

A system is also considered out-of-control beginning in the first hour following the expiration of a previous test if the owner/operator fails to perform a required periodic test.

A system is considered in-control in the hour in which all tests were failed or missed is successfully completed.

1.10 Reporting During Out-of-Control Hours

During the period that the CEMS is out-of-control, not operating, or otherwise determined, based on sound engineering judgment or for a known reason, to be producing inaccurate data, the owner/operator must the following:

1. Repair the analyzer and return it to service.
2. Provide a detailed description of the event in the CEMS logbook.
3. Provide a summary of the downtime in a quarterly report.

Chapter 2.0 Facility and CEM Description

2.1 Facility Description

The JEA - NGS is located at 4377 Heckscher Dr in Jacksonville, FL, which falls under the jurisdiction of EPA's Region IV. The Northside Generating Station is a nominal 1136 MW electric generating plant that consists of a two coal and petroleum coke-fired circulating fluidized bed (CFB) boilers rated at 325 MW each and one oil and natural gas-fired boiler rated at 540 MW. Units 1 & 2, the coal units, exhaust into a dual-flue 495-foot stack. Emissions will be monitored in the individual flues.

The Hg CEMS system configuration and flow diagrams are shown in Figures 2-1 and 2-2 on pages 2-2 through 2-3.

2.2 Stack Diagram

Detailed stack drawings are included as an attachment to this document.

2.3 Analyzer Information

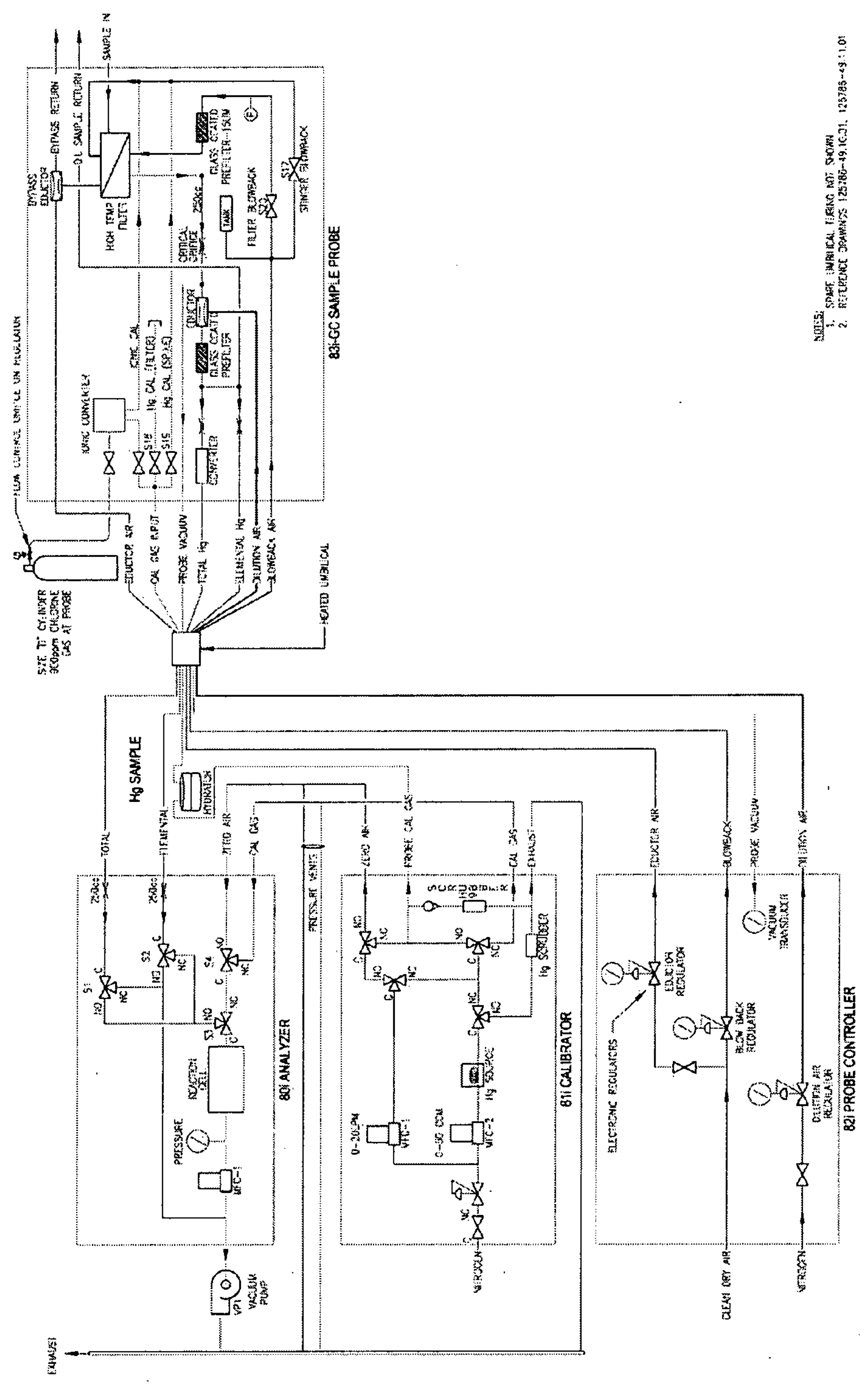
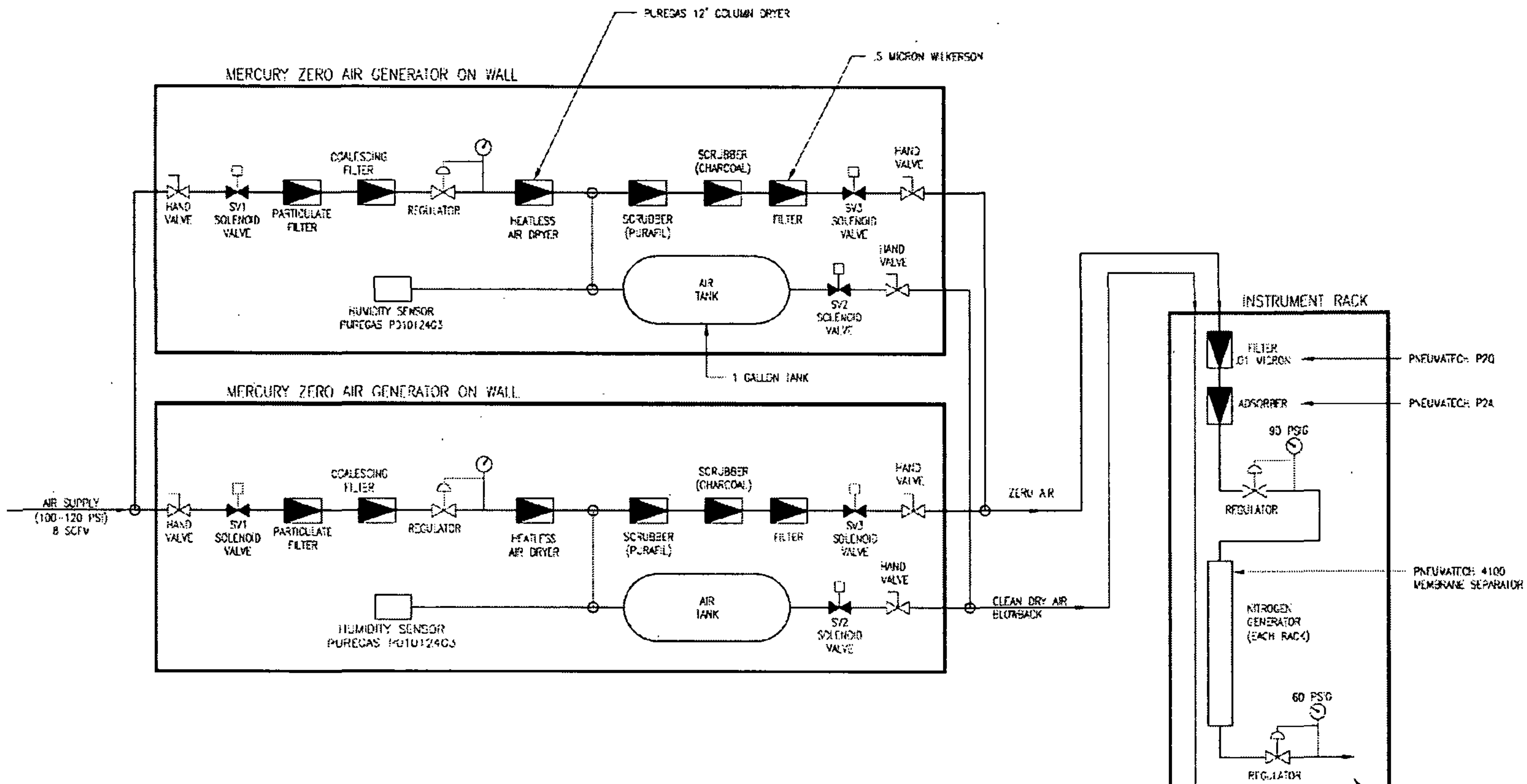


Figure 2-1: Mercury Freedom™ System Configuration

Figure 2-2: Mercury Freedom™ System Flow Diagram



NOTES:

1. REFERENCE DWG # 125786-50.07.03 FOR A PHYSICAL LAYOUT DIAGRAM
2. THE CHARCOAL SCRUBBER CANISTER CONTAINS AN INTEGRAL FILTER ASSY.

2.4 CEM System Description

The Mercury Freedom™ System automatically and continuously measures concentrations of mercury (Hg). The system is connected to the central data logger and Data Acquisition and Handling System (DAHS).

The data logger converts the analog signals to digital signals from the analyzers located in each shelter to digital data. The signals are transmitted to the DAHS links which converts the raw data to the units of the standard and prints out the reports when the appropriate commands are entered. Contact closures are provided for alarms and system status. Complete system operation, including calibration and sequencing is automatic. Operator attention is necessary only for periodic manual verification of accuracy and normal maintenance. Historical data may be downloaded onto disk or tape for reporting, record keeping, or backup.

2.4.1 Mercury Freedom™ System

UNITS 1 & 2

Dilution Ratio: 40:1

Analyzer	Manufacturer/Model	Analyzer Range
Hg	Mercury Freedom™ System	0 – 10 $\mu g/m^3$

The Thermo Mercury Freedom™ System measures mercury, using cold vapor atomic fluorescence (CVAF). The analyzer is capable of measuring either elemental or total Hg. In order to measure elemental Hg, the sample that comes into the probe must be reduced from mercuric chloride to elemental mercury.

Elemental, ionic and total mercury are measured by converting all phases of mercury to elemental mercury for analysis. In CVAF, free-mercury atoms in a carrier gas are excited by a collimated ultraviolet light source at 253.7 nm. The excited atoms re-radiate their absorbed energy (fluorescence) at this same wavelength. Unlike a directional excitation source, fluorescence is omni-directional and may be detected using a photomultiplier tube or UV photodiode. The technique differs from the more conventional atomic absorption (AA) technique in that it is more sensitive, more selective, and is linear over a wide range of concentrations.

The sample enters a chamber where it is excited and decays back to ground state; the UV light given off by the decaying sample is proportional to the concentration. During calibration, the gas from the calibrator flows through the solenoids and the samples bypass the chambers and are sent to the exhaust.

The sampling probe is designed to minimize measurement artifacts due to interactions with fly ash. It uses a high flow sintered metal inertial filter to provide a particulate free, vapor phase sample for analysis. Automated blow back helps to ensure continuous operation and all components exposed to the sample are coated with glass to prevent reactions with mercury. A separate dilution air system for the analyzer is not necessary since the dilution system has been built into the probe. Dilution, calibration and Hg conversion all take place within the probe. A high temperature thermal converter reduces Hg to elemental Hg within the probe before it is sent to the analyzer.

The calibrator uses known concentrations of elemental Hg by combining saturated Hg vapor with Hg-free dilution air or nitrogen. The Hg-free dilution air can be fed with high flow or low flow. Any Hg saturated flow passes through an internal scrubber before being exhausted. The dilution sample probe for Hg is used in drawing a stack gas sample. The system uses an air driven aspirator to extract a sample from the stack. The sample is drawn through a coarse and fine particulate filter. The stack gas is then drawn through a critical orifice and then diluted with air from the aspirator. The air used for dilution and zero air calibrations is provided from the dedicated CEM compressor. The sample is transported via a Teflon sample line to the CEMS shelter and introduced to the analyzer.

A probe controller is included in the Freedom System between the probe and the analyzer. It contains three electro/pneumatic pressure transducers, two are used to adjust and maintain output pressure and blowback, the third adjusts and maintains the dilution air pressure of Hg-free zero air.

The system also includes a Mercuric Chloride Generator which is used in the 3-level system integrity checks. The generator acts as an oxidizer to produce oxidized Hg. This is used during the system integrity check to ensure the reduction of oxidized mercury to elemental mercury is being done correctly. The generator consists of two inlets, one for Hg calibration gas and the other for Chloride gas. The two gases are mixed and the mercuric chloride is sent to the probe for the integrity check.

2.4.2 Equipment Model and Serial Numbers

Description	Model Number	Serial Number
Unit 1		
Mercury Analyzer	80I-ADFNCB	0809128431
Calibration Gas Generator	81I-ANNNAB	1014842165
Unit 2		
Mercury Analyzer	80I-ADFNCB	0805028186
Calibration Gas Generator	81I-ANNNAB	0834733480

2.5 Data Acquisition System

The Data Acquisition System is a pre-existing piece of equipment which will be used in conjunction with the Mercury Freedom™ System.

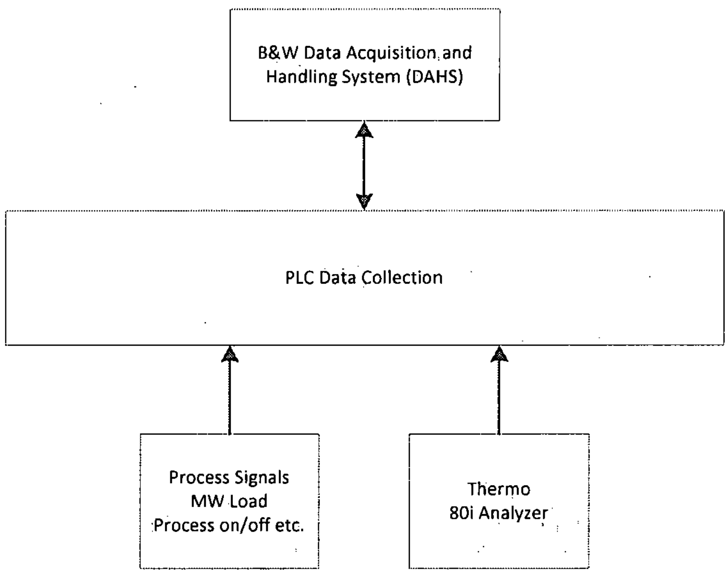
NOTE: For a more detailed description of the Data Acquisition System, please refer to the NGS CEMS/COMS QAP

The B&W Data Acquisition and Handling System (DAHS) is referred to as the NETDAHS. NETDAHS consists of software and two hardware components - a Data Acquisition Computer (DAC), and a Remote Data Collection Node (RDCN). The DAC communicates serially via Ethernet with the RDCN to collect all data and store the data to the computer hard drive. The data is stored as minute averages.The RDCN consists of the programmable logic controller (PLC) modules. Emissions data is collected from the analyzers via the PLC connected to a high-speed local area network using TCP/IP protocol. A number of process-operating parameters are monitored by the RDCN and logged by the DAC. These include calibration control, alarms, analyzer status, and process status.

The NETDAHS DAC consists of a desktop IBM compatible computer, associated hardware and the B&W NETDAHS software. The DAHS provides the functions required to fully meet 40 CFR Part 60 and/or Part 75/Acid Rain. The system also provides a configurable environment to fulfill all state and local regulations as defined by the site's air permit. Reports may be produced in either hard copy or electronic format.

The operating system for the DAC is Microsoft Windows™. B&W's DAC uses all the latest features of the Windows™ operating system to allow the user access to the data collected via a variety of networks and software packages. Open access and connectivity is the key design philosophy behind the many features available.

2.5.1 Data Flow Diagram



2.5.2 NETDAHS Software

The following information outlines the specific features of B&W's NETDAHS software:

Relational Database – B&W's NETDAHS uses SQL Server, an open access relational database that supports standard query language (via OBDC). This database allows users to access the B&W DAHS database via standard system calls over named pipes on a network.

Graphics - All user interface graphics and use point and click, mouse driven menus. Folders, ICONS, and toolbars are provided for ease of use for all program functions. Most user interactions use mouse driven pushbuttons. Pull-down lists are provided to facilitate user interaction. Graphical displays of historical data and present data are provided for viewing on the screen or printing.

Proven B&W NETDAHS Software - All application software C code used by B&W in previous UNIX based applications has been ported over to the 2000 platform and enhanced. This provides the customer with a field-tested and demonstrated product.

Reports - All reports and graphs can be imported directly to either Excel or Word for ease of editing. Once in Excel, the Chart Wizard can be used for generating graphical displays of data.

2.5.3 I/O Controller

The RDCN is built around a series of intelligent input and output modules manufactured by Rockwell Automation that are also known as Programmable Logic Controllers (PLC). The use of the PLC simplifies the design of the system and its maintenance and increases the reliability of the entire system. These modules are packaged for harsh industrial environments and communicate with the DAC using Ethernet. The TCP/IP communications protocol ensures a reliable message delivery system with inherent integrity checks on all messages. The RDCN is mounted inside the CEMS shelter for ease of connection and added protection.

Included in a typical system are analog-to-digital (A/D) converters that convert 4-20 mA signals from the analyzers into digital values. These digitized values are converted into engineering units within the RDCN. The digital input points within the RDCN are used to detect the presence of conditions such as "calibration in progress" or "analyzer fault". The input points can also be used to detect conditions such as "Process On/Off", "Process Startup", or "Process Shutdown".

The RDCN can run in a stand-alone mode (i.e. not connected to the data acquisition computer). Even if the DAC is down, the RDCN continues to calibrate all analyzers. In addition, the RDCN has battery backup memory. Data for each channel can be stored in memory. This ensures that no data is lost if the DAC is down for any reason. When the DAC comes back up, the software "catches up" by retrieving any available data from the RDCN. The data in the RDCN is stored on a "first in first out" (FIFO) basis.

In most PLC installations the PLC software is broken up into two main parts, the processor, and the co-processor. Each part has a dedicated processor to accomplish its task. The first part is the performance of the PLC processor to scan all analog and discrete inputs and control all outputs based on the input status. Also included in this task is the initial qualifying of analog data.

Final analog data processing is done in the co-processor. This co-processor is also the gateway to the DAC, although information may be passed directly from the processor.

2.5.4 Allen Bradley OC-266 INET PLC

The B&W INET controller consists of a proprietary Central Processing Unit (CPU), using Compact Flash memory. The PLC operates a 266 MHz Pentium II The CPU makes decisions based on preprogramming.

The type of user memory for the INET PLC is Compact Flash. Compact Flash is a fast, low-power memory that can easily be examined and changed up to 7 million writes. Compact Flash memory is a non-volatile type of memory. A battery is included in the module to power the on-board clock on the processor.

Faults are handled by a software alarm processor function, which time-stamps and logs I/O and system faults in two tables: PLC Fault Table and I/O Fault Table.

The PLC software structure uses a common architecture that manages memory and execution priority in the Pentium II microprocessor. This operation supports both program execution and basic housekeeping tasks, such as diagnostic routines, input/output scanners, and alarm processing. These routines provide for the upload and download of application programs, return of status information, and control of the PLC.

The INET module provides math functions, report generation, and CEMSPEAK language capabilities. The INET module runs a LINUX operating system. CEMSPEAK is a B&W proprietary programming language that runs in the INET module. The module also contains a serial communications port, which works with ASCII terminals, providing operator program interaction, command level input, printer output, and various other functions.

Baseplate - The baseplate provides backplane connections for the I/O modules for the Allen Bradley Open Controller. All modules operate at 24 VDC. I/O modules are retained in their slots by molded latches that easily snap onto the upper and lower edges of the baseplate, when the module is fully inserted into its slot, to prevent accidentally loosening or disengagement of the modules.

The INET module must be installed in the first slot of the backplane. Module addressing is determined by the position (slot number) in the rack, in which it is installed; there are no jumpers or DIP switch settings required to address modules.

Power Supply Module - The Power Supply Module accepts 120 AC input power, and converts it into 24 VDC output power for an I/O chassis backplane.

Digital Input Module - The DC Input Module converts up to 16 (10 to 30 VDC) inputs to logic-level signals compatible with the PLC. The input section provides terminals for the field wiring coming from the sensing devices in the CEM enclosure. All customer signals are interfaced through relays to the module. The input also provides a visual indication, for the state of each input terminal, with indicators. Another function of the input section is signal conditioning. The input section receives the electrical signal from the machine and converts it to a voltage compatible with the PLC. The Discrete Input Modules convert AC and DC power levels from user devices to the logic levels required by the PLC. An optical coupler provides isolation between the incoming power and the logic circuitry.

Digital Output Module - Each Digital Output Module provides 16 outputs for the PLC. With indicators, the digital output also provides a visual indication for the state of each output terminal.

The Model 30 Discrete Output Modules convert logic levels into AC or DC power levels required for driving user-supplied devices. A power semiconductor provides the drive and isolation for each output point.

Analog Input Module - Each Analog Input Module consists of up to eight analog current inputs. The Analog Input Modules provide A/D conversion by converting an analog voltage into a scaled 12-bit number.

Analog Output Module - The Analog Output Module consists of up to eight analog outputs. The Analog Output Modules provide D/A conversion by converting a scaled 12-bit number into an analog voltage, which is then output as a current.

Chapter 3.0 Responsible Individuals

Throughout this QAP, reference is made to responsible individuals who have the primary responsibility for the procedure in that section. The responsible individuals identified below should review this Plan periodically to ensure that they are familiar with the required procedures.

3.1 Control Room Operators

The Control Room Operators are responsible for monitoring the status of the CEMS, review calibration tests daily and after unit startups, and informing the I&C Technician or Environmental Services Coordinator of CEMS alarms. (There is no tape backup at NGS but rather two mirrored hard drives that automatically back up daily.)

3.2 CEMS Technicians

In this document, "*Technician*" refers to the Instrument & Control CEMS Technicians, or any other individual responsible for adjusting or repairing the CEMS. The Technicians are responsible for performing all CEMS calibrations, adjustments, maintenance, and repair. These responsibilities are detailed throughout this QAP. Technicians are also responsible for keeping themselves familiar with the procedures in this QAP, maintaining detailed maintenance records, and recommending changes if necessary.

3.3 I&C Manager and Foreman

The I&C Manager and Foreman supervise and coordinate the Technicians in the maintenance and repair of the CEMS. They also manage and coordinate CEMS contract maintenance personnel, and works with the Environmental Services Coordinator in reviewing CEMS maintenance activities.

3.4 Environmental Services Coordinator

The Environmental Services Coordinator is the primary individual responsible for ensuring that the CEMS is operated and maintained according to this QAP. The Environmental Services Coordinator is also the primary individual responsible for ensuring that this QAP remains current and accurate. The Environmental Services Coordinator will coordinate CEMS testing, review CEMS system changes and upgrades, and assist in providing upgrades and training to plant employees. The Environmental Services Coordinator will also compile all periodic reports required by regulatory agencies, and assists in other CEMS related activities.

The Environmental Services Coordinator is responsible for all data validation, report generation, and report submittal. The Environmental Services Coordinator will also provide for review and analysis the CEMS Quarterly Emission Reports for the DR.

3.5 Plant Manager

The Plant Manager has the overall responsibility for this facility.

3.6 Designated Representative (DR)

NOTE: THIS SECTION IS NOT CURRENTLY REQUIRED UNDER THE REGULATIONS FOR MERCURY MONITORING.

Chapter 4.0 CEM Startup, Calibration, and Routine Operation

4.1 General

The goal of each CEM system is to provide data that is true, precise, complete, and representative of the gas stream from which it was sampled. Because the operating characteristics of all CEM instruments change over time, these instruments must be calibrated regularly to ensure that data quality remains high.

The JEA Northside Generating facility analyzers are automatically calibrated each day. This calibration is initiated and controlled by monitors. During calibration, the sample stream is temporarily turned off and calibration gases are flowed to each of the analyzers.

Two gases are required for the daily calibration procedure. A "zero" or low concentration gas is used to test the baseline response of each instrument. A "span" or high concentration gas is then used to test the response of the instrument at the high end of its range. These two gas concentrations are then utilized in performing the daily and quarterly assessments for running calibrations and linearity checks. Other ranges may be introduced besides the low and high gas concentrations, to verify and establish the linearity of the analyzers (i.e.: a mid-range) during the quarterly linearity check.

Table 4-1: Analyzer Span

Analyzer	Span	Unit of Measure
Hg	10	ug/scm

4.1.1 Instrument Level vs. Probe Tip Calibration

For an instrument calibration check, gases are introduced at the flow panel in order to conserve calibration gas. This is referred to as an "instrument level calibration". However, for the daily calibration of the sampling system, the gases must be introduced near the probe. This is referred to as a "probe tip calibration". Probe tip calibrations must also be performed whenever there is any change to, or maintenance of, any portion of the gas handling and conditioning system. It must also be performed prior to the quarterly QA audit. A probe tip calibration value which deviates by more than 5% from the instrument calibration value indicates that there may be a problem (leaks, condensation, etc.) with the sample transport/conditioning sy stem.

4.2 The Sample Analysis System

To fully understand the calibration process and the effect it has on instrument performance, it is necessary to examine the sample analysis system more closely. The sample analysis system consists of the mercury analyzers. In the most general terms, a gas sample is introduced into the analyzer. The analyzer measures some physical property of the gas which is (ideally) unique to the pollutant of interest and produces a response which is proportional to the concentration.

It is important to understand several characteristics of analyzers which relate to the calibration process and to data interpretation. These are:

- Linearization
- Analyzer Drift
- Drift Compensation

- Interference

4.2.1 Linearization

The detector is the heart of any pollutant analyzer. The detector translates pollutant concentration into an electronic signal that is proportional to the pollutant concentration. This signal can then be interpreted by a data recording device.

Frequently, the relationship between pollutant concentration and detector response is non-linear. To compensate for this fact, some vendors provide electronic linearizer circuits internal to the analyzer. These circuits compensate for non-linear detector output.

Other vendors may provide a multi-point linearization table which allows the data acquisition and handling system to perform the linearization function.

A few manufacturers characterize an entire instrument line with a single linearization curve. This does not provide accurate characterization of an individual instrument and may require a multi-point calibration to accurately characterize the response of the instrument.

4.2.2 Analyzer Drift

The operating characteristics of any instrument change from day-to-day, indeed they change continuously. For example, instrument optics degrade by accumulation of a particulate matter or condensation film; critical optical alignments shift from vibration; and the characteristics of light sources, which are used in many analysis systems, change as they age. In addition, there are continuous, random fluctuations in electrical quality, ambient temperature and pressure which also affect instrument performance.

This change in analyzer response over time is called "drift." Drift may be either random or directional. Random drift may be caused by environmental factors such as electronic or electrical noise or temperature and pressure variations in the sample cell. Climate controlled instrument enclosures and electrical power conditioners are often used to minimize these environmental factors. Over time, random drift tends to cancel itself out.

Directional drift is generally caused by the degradation or contamination of analyzer components over time. This degradation or contamination may cause the analyzer response to drift in either a positive or negative direction depending on th e type of analyzer.

Each system will be checked for drift through daily calibrations. If drift is detected, the CEM operator has three options:

- Do nothing. Minor variations due to random drift will always be present. Attempting to continually compensate for minor random drift is an exercise in futility. CEM regulations specify when the cumulative drift is substantial enough to warrant other action.
- Compensate for the drift by applying a compensation factor to all data generated. When cumulative drift becomes substantial it may indicate a directional drift problem. An adjustment must then be made to all data to compensate for the drift.
- Identify and correct the root cause of the drift. When drift compensation is applied continuously to compensate for directional drift, the accuracy and precision of the data may suffer. When two or more consecutive compensations of the same direction and magnitude are necessary, corrective action should be initiated to identify and correct the problem causing the excessive drift. After the corrective action has been completed, the instrument may require manual re-calibration.

4.2.3 Drift Compensation

When cumulative analyzer drift becomes "excessive" (twice the performance specification), a compensation factor must be applied to all data in order to re-establish an accurate relationship between the pollutant concentration and the data output. Automatic compensation, when required, can be enabled by the operator. Currently, manual corrections are made at the analyzers.

Data compensation is often referred to as "data correction". However, this is a misnomer, since continually adjusting the data to compensate for directional drift does not correct the underlying problem. When drift compensation is applied continuously in lieu of corrective action, the accuracy and precision of the instrument may suffer.

In an absorption-type instrument, as the sample cell degrades the detector receives less light energy. The effective span of the instrument decreases as a result of this light attenuation. This results in a decrease in the accuracy of the analyzer. Data acquisition systems compensate for the changes in zero and span but cannot increase analyzer accuracy once it is lost.

When two or more consecutive compensations of the same direction and magnitude are necessary, corrective action should be initiated to identify and remedy the problem causing the excessive drift. After the corrective action has been completed, the instrument may require re-calibration.

4.2.4 Interference

Interference occurs when one or more constituents of a gas stream create the same analyzer response as the pollutant of interest, resulting in data which is biased high. Interference may also occur when detection of the pollutant of interest is blocked by the presence of one or more constituents of the gas stream, resulting in data which is biased low.

Each analyzer contained in the CEMS is required to demonstrate the lack of interference from the specific components contained in the units exhaust gas stream. It is suggested that one (1) of the following directions be adopted:

- Obtain an analyzer that is "immune" from the interference in question. Check with the vendor to provide you with a certificate and/or data that the analyzers are not going to be affected by the constituents in the gas stream.
- Conduct an interference check on each analyzer following guidelines as specified in 40 CFR 60, Appendix A, EPA Method 20, Section 5.4 "Interference Response". (Note: If this option is selected it is suggested that the gases used for the interference check be similar to actual exhaust gas values.)
- Measure the interfering substance. In the event the sum of interference responses for any analyzer is greater than 2.5 % of the applicable span value, corrective action must be taken to remove the substance from the gas stream prior to analysis.

In this instance the first option was adopted. The Thermo Mercury Freedom System is designed to be immune from interference from the components of the stack gas.

4.3 General Calibration Concepts

The DAHS at the Northside Generation Station is programmed to perform a calibration sequence beginning at a specific time each day. In addition to these automatic calibrations, manual calibration should be performed prior to the quarterly audit or after any invasive QC procedure. Manual calibrations allow the operator to make an electronic compensation for drift. Both instrument level and probe tip calibrations can be performed manually.

4.3.1 Manual Instrument Level Calibration Procedure

Check the vendor's manual for analyzer manual calibration procedures. Instrument Level Calibrations are initiated at the analyzer.

The following describes the general procedure for manual analyzer calibration:

Calibration Drift

Verify that the response is within manufacturer's written specifications. If it is not within the written specifications, the CEMS is considered out-of-control. It is extremely important to ensure that the response is within specifications to limit errors associated with contamination or degradation of the analyzer components.

Calibration Error

Verify that the response is within manufacturer's written specifications. If it is not within the written specifications, the CEMS is considered out-of-control. It is extremely important to ensure that the response is within specifications to limit errors associated with damage of the analyzer components and to minimize out-of-control periods.

Instrument Flow Check

Verify that the gas flows are within manufacturer's written specifications. It is extremely important to ensure that the flows in all modes (sample, zero and span) are within specifications to limit errors associated with sample cell over pressure and sluggish response times.

Zero Adjustment

On any instrument, the zero adjustment should be made first. This ensures the baseline of the instrument is set to zero and allows an opportunity to identify and correct any zero noise and to compensate electrically for any directional drift.

Span (Gain) Adjustment

Following the initial zero adjustment, the span adjustment must be performed. This adjustment will compensate electrically for any decrease in detector sensitivity (directional drift) and adjust the response of the analyzer to a traceable standard (the calibration gas).

Zero/Span Check

Following any span adjustments, it is important to verify that the zero baseline has not shifted. If a change is noted, an adjustment to the instrument must be made. Whenever an adjustment to the zero or the span is made, a subsequent check to the span or zero must be made. This check process must continue until no further adjustments are made.

Automatic Calibration

After any manual calibration on any instrument, an automatic calibration must be performed. This allows the data acquisition system to reset the compensation factors it applies to the data if the automatic compensation option of the DAS is enabled. Currently, manual corrections are made at the analyzers.

Linearity and System Integrity Check

A weekly single point system integrity check must be performed and a quarterly three point integrity check or linearity check must be performed. It is extremely important to ensure that the error in linearity and integrity does not deviate from the reference value.

4.3.2 Manual Probe Tip Calibration Procedure

After a complete manual instrument level calibration (where the calibration gas is run directly into the analyzer), a check of the sample transport and conditioning system should be made. This may be accomplished either manually or through the DAHS.

Important Note: The probe tip calibration is a diagnostic check only and no adjustments are to be made.

Warning: If the probe tip calibration deviates by more than 5% from the instrument level calibration, there may be problems with the sample transport/conditioning system.

The numbers of the instrument calibration and the DAHS probe tip calibration (check of the sample transport and conditioning system) should match within 5%. If they are not, then a bias exists in the sample transport and conditioning system, which needs to be addressed through initiation of Corrective Action.

4.3.3 Automatic Calibrations

The automatic probe tip calibration is the "Daily Calibration" that is performed each morning. The parameters for this calibration have been programmed into the DAHS and no action on the part of the CEM operator is required to initiate this procedure.

4.4 Calibration Procedures

The system includes: 80i, Model 81i, 82i, 83i, 83i GC, and the Mercury Chloride Generator. Of these, Model 80i and Model 81i have specific calibration procedures. Model 80i controls the calibration for the entire system. The calibration procedures include both elemental Hg and total Hg being calibrated simultaneously. Model 81i has been factory calibrated and does not require routine calibration.

4.4.1 Frequency of Calibration

The following sections detail the calibration procedures for the Mercury Freedom™ System and can also be found in the User Manual.

Table 4-2: Calibration Frequency

	Specification	Acceptance Criteria		Calibration Standard
Daily	Zero and Span*	Zero and Span Checks indicate a shift in instrument gain of < 5%		Elemental Hg or Oxidized Hg standard
Weekly	System Integrity Check	≤ 10% of the reference value		Oxidized Hg standard
Quarterly	Linearity Check	≤ 10% of the reference value		Elemental Hg standard
Yearly	RATA	annual test using current industry standard and regulatory practices		Elemental Hg or Oxidized Hg standard

*Also run prior to initial Start-up

4.4.2 Initial Start-up Calibration for Model 80*i*

To calibrate the Model 80i, the Model 81i Calibrator is required. In turn, a zero air source is required for feed gas to the 81i Calibrator.

Drying

Several drying methods are available. Passing the compressed air through a bed of silica gel, using a heatless air dryer, or removing water vapor with a permeation dryer are three possible approaches. Any air dryer should be preceded by an oil/water coalesces.

Scrubbing

Fixed bed reactors are commonly used in the last step of zero air generation to remove the remaining contaminants by either further reaction or absorption. Table 4-3 lists materials that can be effective in removing contaminants.

Table 4-3: Scrubbing Materials

To Remove	Use
Hydrocarbons	Molecular Sieve (4A), Activated Charcoal
O_3, Hg^0 and SO_2	Activated charcoal

4.4.3 Pre-Calibration Procedure

Note: The calibration and calibration check duration times should be long enough to account for the transition (purge) process when switching from sample to zero and from zero to span.

Depending on the plumbing configuration and the instrument, data from approximately the first several minutes of a zero calibration or check should be disregarded because of residual sample air. Also, data from approximately the first several minutes of a span calibration or check should be disregarded because the span is mixing with the residual zero air.

1. Allow the instrument to warm up and stabilize overnight.
2. Check to see that there are no alarms.
3. Be sure the instrument is in the auto mode, that is, Hg^0, Hg^{2+}.
4. Hg^t measurements are being displayed on the front panel display. If the instrument is not in auto mode:
   a. Press [menu] to display the Main Menu, then choose Instrument Controls > Auto/Manual Mode.
   b. Select Hg(0)/Hg(t), and press [enter].
   c. Press [enter] to return to the Main Menu.
5. From the Main Menu, select Averaging Time to display the Averaging Time screen. It is recommended that a higher averaging time be used for best results.

Note: During an auto calibration, the averaging time should be less than the zero duration and less than the span duration.

4.4.4 Calibration Procedure

In order to calibrate the Model 80i analyzer, first connect the CAL GAS from the 81i to the SPAN port on the 80i. Ensure that an atmospheric dump is present. Connect the ZERO AIR from the 81i to the ZERO port on the 80i.

4.4.4.1 Setting Hg^0 and Hg^t Background to Zero

Note Hg^0 is equivalent to Hg ELEMENTAL and Hg^t is equivalent to Hg TOTAL

1. Put the Model 80i in Inst Zero mode.
2. Put the Model 81i in Analyzer Zero mode.
   a. Allow instrument to sample zero air until the Hg^0, Hg^t, and Hg^{2+} readings stabilize
   b. Next, choose Calibration > Cal Hg(0) Background from the Main Menu
   c. Press [enter] to set the Hg(0) reading to zero.
   d. Press [menu] to return to the Calibration menu.
   e. Repeat this procedure to set the Hg^t background to zero.
3. Set the 80i to Analyzer Span mode and set the desired calibration concentration using one of the six preset span values in the 80i (Calibration > Inst Hg Span Conc.).

4. Set the 80i to Analyzer Span mode.

4.4.4.2 Setting the Hg0 Channel to the Hg0 Calibration Gas

1. Allow the instrument to sample the Hg0 calibration gas until the Hg^0, Hg^t, and Hg^{2+} readings stabilize.
2. Next, choose Calibration > Calibration Hg^0 Coefficient from the Main Menu.
3. Enter the output conc. at the model 81i (the Hg^0 calibration gas concentration) in the SPAN CONC line of the display. The Hg(0) line of the Calibrate Hg(0) screen displays the current Hg^0 concentration. Use the left and right arrows to move the cursor left and right and use the up and down arrows to increment or decrement the numeric character at the cursor.

4.4.4.3 Calibrating the Hgt Channel

Note: Since the Hg^{2+} converter is located in the Model 83i, Hg^0 cal gas should be used to calibrate the Model 80i if it is used as a stand-alone unit. Do not introduce Hg^{2+} gas directly into the 80i without running it through a converter.

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1. Press  to return to the Calibration menu, and choose Cal Hg(t) Coefficient. The Hg^t line of the Calibrate Hg^t screen displays the current Hg^t concentration. Enter the Hg^0 calibration gas concentration from the 81i into the SPAN CONC line of the display.
2. Press  to calculate and save the new Hg^t coefficient based on the entered span concentration.
3. Record the Hg^t concentration and the instrument's Hg^t response if desired.

4.4.4.4 Daily Zero and Span Checks for the Model 80i

The system calibration check requires the calibration gas to go through all system components. The calibration check must be done daily with either Hg^0 or $HgCl_2$. Since the system uses a converter, if elemental Hg is used, you must do weekly system integrity checks. The 80i automatic calibration check requires the following pre-conditions:

Analyzer Service Mode must be OFF.

Analyzer must control the Calibrator.

1. Allow instrument to sample zero gas until a stable reading is obtained on the Hg^0, Hg^t, and Hg^{2+} channels then record these readings.
2. Attach a supply with known Hg^0 concentration to the sample port (Hg TOTAL or Hg ELEMENTAL) or SPAN bulkhead.
3. Allow instrument to sample the calibration gas until a stable reading is obtained on the Hg^0, Hg^t, and Hg^{2+} channels and record these readings.
4. This check can be repeated for the system using system zero/system span gas modes. Stabilization time will vary.

Note: For frequency of calibration, see Section 6.1.

4.4.5 Calibration for the Model 81i

The Model 81i is calibrated to NIST standards at the factory and should not require calibration prior to startup. However, when a mass flow controller or pressure transducer is replaced it must be calibrated before operating the instrument.

IMPORTANT NOTE The replacement or recalibration of any component will void the overall NIST Traceability of the Model 81i and will require re-certification.

4.4.5.1 Mass Flow Controller Calibration

In order to calibrate the mass flow meter section of the zero or gas mass flow controller, a NIST traceable flow meter is required. The term calibration means determining the actual flow versus the flow setting for seven equally spaced flows along the range of the device. The Model 81i then corrects the output according to an internal algorithm.

Calibration may be done with a properly calibrated flow meter. For the most accurate calibration procedure, use a volumetric NIST traceable calibrator with the following step-by-step calibration procedure.

1. Connect a source of clean, dry air to the inlet of the mass flow controller.
2. Measure barometric pressure and room temperature.
3. Connect a suitable flow meter to the mass flow controller outlet.
4. Set Model 81i to Hg Flow or Zero Air Flow Calibration.
5. Set flow controller to 95 percent of full scale, then wait until flow meter reading stabilizes.
6. Enter the flow meter reading using the flow input screen.
7. Repeat Steps 5 and 6 for the remaining flow settings.

If you encounter a flow controller malfunction, contact Thermo Fisher Scientific.

4.4.5.2 Cooler Temperature Calibration

Use the following procedure to calibrate the cooler temperature when the cooler temperature does not match the cooler set temperature.

1. Connect an appropriate resistor for the desired setting temperature to J24 pins 1 and 2 on measurement interface board. For example, for a temperature of 14°C, use a resistor with a value of 15,797 Ohms. Refer to the following table for a list of resistors and associated temperature values.

Note: After plugging in the test resistor, it may take several minutes for the reading to stabilize.

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1. From the Main Menu, press ↓ to scroll to Service, press ↵ > ↓ to scroll to Cooler Temp Calibration, and press ↵. The Calibrate Cooler Temp screen displays. If Service is not displayed on the Main Menu, use the following procedure to display it:
   a. At the Main Menu, press ↓ to scroll to Instrument Controls, press ↵ > ↓ to scroll to Service Mode, and press ↵. The Service Mode screen displays.
   b. Press ↵ to toggle the Service Mode to ON.
   c. Press ■ > ■ to return to the Main Menu.
   d. Continue the procedure at Step 2 to access the Calibrate Cooler Temp screen.
2. At the Calibrate Cooler Temp screen, use ↑ ↓ until the temperature reads 14°C, then press ↵ to save the value.

Table 4-4: Temperature Values and Associated Resistors

Temperature (°C)	R Value (Ohms)
0	29,490
1	28,157
2	26,891
3	25,689
4	24,547
5	23,462
6	22,430
7	21,450
8	20,517
9	19,631
10	18,747
11	17,983
12	17,219
13	16,490
14	15,797
15	15,136
16	14,507
17	13,906
18	13,334
19	12,778
20	12,268

4.4.6 Calibration of Models 82i, 83i, and Mercuric Chloride Generator

All of the components of the Mercury Freedom™ System work together as one whole unit. The calibration procedures for Model 80i serve as calibration procedures for the system as a whole; due to this, Models 82i, 83i, and the generator do not require their own specific calibration procedures.

Chapter 5.0 Quality Control Activities

5.1 Introduction

Quality Control (QC) is the procedures, policies, and corrective actions necessary to ensure product quality. QC procedures are routine activities. These activities include but are not limited to daily calibrations and routine maintenance.

5.2 Maintenance Policy

A thorough and consistent maintenance program is essential for the collection of high quality CEMS data. The guidance provided in this section shall be followed completely and consistently to ensure high data integrity and availability.

The materials in this section, as well as the associated standard operating procedures, have been adapted from material supplied by the equipment vendor. In many cases, these materials have been modified to accommodate the unique characteristics of the system installed at this facility. In situations where this document does not cover a particular topic of concern, the vendor's documentation shall be used as a guide.

As inspection and maintenance procedures evolve, this document shall be updated at least annually by Environmental Services Coordinator, approved by the Plant Manager and the QA/QC team, so as to reflect actual current practice.

The specific preventative maintenance procedures can be found in the worksheets in this section.

5.3 System Maintenance Log

In order to ensure consistency and follow-through on system maintenance and to provide documentation of system operation, a log shall be kept of any system malfunctions, maintenance, adjustments, inspections or operator observations. This log shall consist of electronic entries in the Ops Log and Work Order entries in the Maximo Maintenance Management System.

5.4 Daily Inspections and Preventative Maintenance (I/PM)

The CEM systems shall be inspected daily by the I&C Technicians. The daily inspection checklist shall be filled out completely and filed as part of the maintenance log of the system. The objectives of the daily inspections are to:

- Check that all instruments are operating within checklist parameters;
- Check that all gas flows are within specified limits;
- Verify that required daily calibrations have been performed;
- Review results of daily calibration for possible system adjustment;
- Inspect suspected "trouble spots" as a preventative measure;
- Check that all consumables are present in sufficient quantity for the day's activities;
- Check that all data collected is being properly analyzed and stored.

This daily inspection is designed to provide a quick overview of the operation of the system. It should take no longer than one (1) hour to complete. This time includes about 30 minutes to inspect the instruments of the CEM systems and 30 minutes in the CEMS Shelter reviewing data.

In addition to completing a daily checklist, the System Maintenance Log shall be updated each day. Descriptions of the entries for various situations are described below.

5.4.1 System Maintenance Log Entry – No Areas of Concern Identified

If the daily inspection uncovers no problems or potential problems, an entry shall be made in the System Maintenance Log. The entry shall consist of:

- the date;
- a notation that the daily inspection was performed and that no problems were found;
- the signature of the Technician.

5.4.2 System Maintenance Log Entry – *Areas of Concern Identified*

If problems or areas of concern are discovered during the daily inspection, an entry shall be made in the System Maintenance Log. The entry shall consist of:

- the date;
- a notation describing the problem or potential problem;
- a notation describing the corrective action which will be taken;
- who is responsible for performing the corrective action;
- a completion date for the corrective action;
- the signature of the Technician;
- optional condition of how the system was left (i.e.) needs calibration, parts in operable, etc.).

If a Work Order is submitted, the third, fourth and fifth items may be omitted. A reference to the Work Order number must be made in the System Maintenance Log. This is essential since it provides the critical link between the System Maintenance Log and the Work Order.

5.5 Monthly I/PM

The monthly inspection and preventative maintenance (I/PM) activities shall be completed and logged as part of the System Maintenance Log.

Log entries, problem reports, and documentation of problem resolution shall be handled according to the procedures outlined in the Corrective Action Program.

5.6 Quarterly I/PM

The quarterly I/PM is the major system diagnostic procedure. It requires more invasive inspection and testing than any other I/PM. This I/PM shall be performed two (2) to three (3) weeks before the quarterly QA audit. This allows enough time to identify and correct any problems that may impact the results of the audit. The quarterly I/PM checklist shall be filled out completely and filed as part of the maintenance log of the system.

Important Note: If the quarterly QA/QC Testing shows inadequate system performance, the quarterly I/PM activities (or an appropriate subset of these activities) shall be performed monthly until consistent, acceptable performance is achieved.

Log entries, problem reports, and documentation of problem resolution shall be handled according to the procedures outlined in the Corrective Action Program.

5.7 Problem Reports and Initiation of Corrective Action

Whenever a problem or area of concern is identified or found during an inspection, it shall be reported to the Maintenance Supervisor. If the problem is non-routine or major, a Corrective Action Worksheet shall be submitted to the I&C Maintenance Manager or Foreman.

The Environmental Services Coordinator and I&C Manager or Foreman shall be responsible for reviewing the situation and/or the Corrective Action Worksheet, determining whether corrective action is required, deciding on an appropriate timetable, and issuing work orders or taking other steps to ensure that corrective actions are taken. The Environmental Services Coordinator and I&C Manager or Foreman are also responsible for verifying that the corrective action has been taken and that the problem is resolved.

5.8 Documentation of Problem Resolution

Upon verification that the problem is resolved, the *I&C Technician* shall make an entry into the System Maintenance Log. The entry shall consist of:

- the date;
- a notation referring to the initial problem entry in the log;
- a description of any changes or modifications to the corrective action as described in the initial problem entry;
- a notation that he/she has verified that the corrective action has been taken and the problem is resolved;
- the signature.

(Note: If a Corrective Action Worksheet is filed, this entry may be omitted.)

5.9 Corrective Actions Requiring Additional Testing

Any change that affects the monitors measuring systems or analysis systems in such a way that measurements or calibrations have changed significantly (including the DAHS) shall require additional testing. Change resulting from routine or normal corrective maintenance and/or quality assurance activities do not require recertification, nor do software modifications in the automated data acquisition and handling system, where the modification is only for the purpose of generating additional or modified reports.

The following are examples of situations that require addiontal testing. These changes include, but are not limited to, the following:

- Changes in gas cells;
- Path lengths;
- Sample probe;
- System optics;

- Replacement of analytical methods (including the analyzer(s), monitor(s));
- Change in location or orientation of the sampling probe or site;
- Rebuilding of the analyzer or all monitoring system equipment.

5.10 Routine Maintenance

This section contains suggestions for performing routine preventive maintenance. For detailed maintenance procedures, refer to the manufacturers' instruction manuals and other technical data included under separate cover(s).

5.10.1 Abnormal Measurement Output Voltage

If output voltage/current range is not between the required range for each analyzer and calibration is completed successfully, refer to the analyzer manufacturer's instruction manuals for adjustment and/or repair information.

5.10.2 Water Contamination

Following a sample-failure-alarm, first check for any water in the moisture sensor bowl or a high cooler temperature. To find the cause of the water contamination, proceed as follows:

1. Check to see that the temperature of the sample gas cooler is at least 35°F.
2. Remove, dry out, and replace the moisture-sensor filter-elements.

5.11 Routine Maintenance for the Sample Probe

The probe has no moving parts. It does have a particulate filter and an electric heater. The electric heater can be checked by using a clamp-on AC amp meter to detect current on the power wires going from the analyzer cabinet into the sample line up to the probe. The probe also has a low temperature alarm contact that will detect an inoperable probe heater. The filter is manually checked as part of scheduled routine maintenance as described later.

5.12 Routine Maintenance for the Sample Line

The sample line requires no maintenance. However, it is advisable to inspect periodically the sample line visually to detect any damage or wear due to rubbing, vibration, physical damage, etc. If the sample line is installed properly, there should be no stress points that could cause the tubing to become kinked in any manner. Typical life of the heat-trace sample-line is approximately 10-12 years depending on the temperature maintained and ambient conditions. Sample line heat trace is not a serviceable item and thus would require replacement in its entirety.

5.13 Preventative Maintenance Schedule

This section contains a suggested schedule, Form 5-1, for performing preventive maintenance. Maintenance schedule may vary depending upon site-specific conditions.

ThermoFisher
SCIENTIFIC

11/27/2006

Preventative Maintenance Schedule for Mercury Freedom System

This document is a guideline only, many items are site specific
See recommended spares list for part numbers and pricing

		Monthly	Quarterly	Semi-Annually	Annually
Model 80	Clean outside of case	x			
	Visual Inspection and cleaning	x			
	Critical orifice inspection (qty 2)	x			
	Fan filter inspection	x			
	Lamp voltage/frequency check	x			
	Leak Test				x
	Replace analyzer lamp				x
	Daily analyzer worksheet				
Model 81	Cleaning outside of case	x			
	Chiller fins inspection and cleaning	x			
	Fan filter inspection and cleaning	x			
	Leak test				x
	Replace scrubbers				x
	Daily calibrator worksheet				
Model 82	None				
Model 83	Hg converter core replacement			x	
	15 micron filter				x
	Hg scrubber (elemental channel)			x	
	Thermocouple converter				x
	Preventative maintenance kit				x
	Clean inertial filter with brush		x		
	Clean out inlet and outlet stingers		x		
System	Cleaning sample lines (2)				x
	Check indicating silica gel on dryer	x			
	Replace Dryrite				x
	Replace carbon				x
	Replace Purafil				x
	Filter for black canister (Cl)				x
	Pump replacement				as needed

Figure 5-1: Sample Preventative Maintenance Schedule

Chapter 6.0 QUALITY ASSURANCE ACTIVITIES

Quality Assurance (QA) is a series of checks performed to ensure the QC procedures are functioning properly. The activities include, but are not limited to, quarterly and annual audits.

6.1 Daily Calibration Error Tests for the Hg Monitors

The I&C Technician is responsible for reviewing the CEMS Calibration Report each day and to report any CEMS alarms to the Environmental Services Coordinator as soon as possible after an alarm is detected. The I&C Technician is also responsible for ensuring that calibration error and calibration drift tests are initiated after a unit startup, according to the frequency and test requirements of this section.

The I&C Technician is responsible for taking corrective actions when calibrations are outside of acceptable standards, and repeating tests when necessary. The I&C Technician shall report problems or failed calibration tests to the Environmental Services Coordinator.

The Environmental Services Coordinator is responsible for ensuring that the calibration checks and adjustment procedures in this Section are performed according to this QAP. The Environmental Services Coordinator should periodically review CEMS calibration error data to ensure the tests are within the accuracy requirements and that the reports are filed for recordkeeping.

A two-point calibration error test of the Hg (for Units 1 and 2) monitors is performed automatically once during each unit operating day. The manufacturer recommends the daily calibration error tests to be performed during quality assurance testing. This is because the readings from the CEMS are affected by temperature and pressure conditions.

In general, all daily calibrations must be performed while the units are on-line. However, daily calibrations may be performed when the unit is off-line if the monitoring systems pass an "off-line calibration demonstration" as described below. ***Note that this test must be conducted for each stack and each analyzer.***

6.1.1 Conducting the Daily Calibration Error Test

The two-point calibration error test calculates the calibration error for two gas concentrations. During calibration, the system controller flows calibration gases to the probe. The monitors are challenged once with each level of the calibration gases. Each gas flows for approximately 10 minutes. The monitor response is recorded by the DAHS.

Do not make manual adjustments to the monitor settings until after taking measurements at both zero and high concentration levels for that day.

The DAHS compares the actual analyzer reading with the expected value of the calibration gas. If the analyzer drift exceeds the specification limits, the failure is indicated on the calibration report. When the daily calibration exceeds the specification limits, this indicates a need for corrective actions. Corrective actions may include, but are not limited to, manual calibration of the failed analyzer.

6.1.2 Daily Calibration Error Test Results

Daily Calibration Error Test Results may be viewed two ways, using CalHist or by viewing the Daily Calibration Report.

To view in CalHist, single click on the Calibrations and Constants tab from the Main Menu, then select Calibrations History. Select the appropriate channels and time frame and click "OK". The results will take a moment to appear.

To view as a report, select Reports from the Main Menu, and then select Generate/Configure Reports. Select the appropriate report and time frame, then single click "Generate". Once the report is generated, single-click "View" to view the report.

The error limit for a Daily Calibration Error Test is +/- 0.8µg/scm.

6.1.3 Out-of-Control Limits

A calibration error (CE) is required to be initiated for every 24- to 26-continuous-hour period, for zero and span drift assessments. In the event that the drift exceeds the limitations, the CEMS is deemed out-of-control.

The out-of-control period begins with the hour of the failed calibration error test and ends with the hour of the next satisfactory calibration error test after corrective action. If the failed calibration error test, corrective action, and satisfactory calibration error test occur within the same hour, the hour is not considered out-of-control if two or more valid readings are obtained during the hour.

The DAHS records the calibration-error-test-results and "flags" the calibration report if the recalibration (or out-of-control) criteria are exceeded. Recalibration or corrective action is taken when the failure is identified.

During the period, the CEMS is out-of-control; the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.

6.2 Daily Assessment Start-Up Grace Period

A start-up grace period may apply when a unit begins to operate after a period of non-operation. The requirements to qualify for a start-up grace period are as follows:

1. The unit must have resumed operation after being in outage for 1 or more hours (i.e., the unit must be in a start-up condition) as evidenced by a change in operating time from zero in one clock hour to an operating time greater than zero in the next clock time.
2. For a monitoring system to be used to validate data during the grace period, the previous daily assessment must have passed on-line within 26 clock hours prior to the last hour in which the unit operated before the outage. The monitoring system must also be in-control with respect to quarterly and semi-annual or annual assessments.

If these conditions are met, then a start-up grace period of up to eight (8) clock hours applies, beginning with the first hour of unit operation following the outage. During the start-up grace period, data generated by the monitoring system are considered quality-assured. A start-up grace period for a calibration error test ends when:

1. A daily assessment (calibration error test or flow-interference check) is performed; or
2. Eight (8) clock hours have elapsed (starting with the first hour of unit operation following the outage), whichever occurs first.

6.3 Data Recording and Data Validation

Record and tabulate all calibration-error test data according to month, day, clock-hour, and magnitude in ppm, or percent volume (as applicable to individual applications). For program monitors that automatically adjust data to the corrected calibration values either record the unadjusted concentrations measured in the calibration error test prior to resetting the calibration or the magnitude of any adjustment.

When a monitoring system passes a daily assessment (daily calibration error test), data from that monitoring system are considered valid for 26 clock hours (24 hours plus a 2-hour grace period.) The 26 clock hours begin with the hour in which the test is passed, unless another assessment is failed within the 26-hour period. These other assessments consist of additional calibration error checks, or a quarterly linearity check, or a relative accuracy test audit.

Data is considered invalid, beginning with the first hour following the expiration of a 26 hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up period (refer to next section), if a subsequent passing daily assessment has not been conducted.

If an on-line daily calibration error test of the monitoring system is not conducted and passed within 26 unit-operating hours of an off-line calibration error test that is used for data validation, then data from that monitoring system are invalid beginning with the 27^{th} unit-operating hour following that off-line calibration error test.

6.4 Quarterly Assessments

The following assessments will be performed during each calendar quarter that the unit combusts fuel.

6.4.1 Linearity Check

The Environmental Services Coordinator is responsible for ensuring that quarterly linearity checks are performed according to the procedures in this QAP. The Environmental Services Coordinator is also responsible for reviewing the linearity check schedule to ensure that the audits are performed according to the required frequency. The Technician are responsible for informing the Environmental Services Coordinator when major CEM analyzer maintenance or setup changes occur (i.e., changes in analyzer span values, major analyzer repairs, or new analyzers are installed) so that the Environmental Services Coordinator can determine if a linearity check may be required.

The Technician is responsible for performing the actual linearity check audit. The Technician is also responsible for taking corrective actions when test results are outside of acceptable standards, and repeating these checks when necessary.

The CEM linearity check is performed once each. The linearity check is performed by repeatedly challenging the CEM systems with three (3) concentrations of calibration gas. The difference between the actual concentration of the audit gases and the concentration indicated by the analyzer is used to assess the overall accuracy and linearity of the CEM systems. A linearity check is not required in quarters with less than 168 operating hours.

6.4.2 Viewing the Results

Linearity Check Test Results may be view two ways, using CalHist or by viewing the Linearity Calibration Report.

To view in CalHist, single click on the Calibrations and Constants tab from the Main Menu, then select Calibrations History. Select the appropriate channels and time frame and click "OK". The results will take a moment to appear.

To view as a report, select Reports from the Main Menu, then select Generate/Configure Reports. Select the appropriate report and time frame, then single click "Generate". Once the report is generated, single-click "View" to view the report.

The error limit for a Linearity Check is +/- 1.0 µg/scm

6.4.3 Data Validation – Linearity Check

A linearity check cannot be performed if the monitoring system is operating out-of-control with respect to any required daily or semiannual quality assurance.

The linearity check may be done after performing only routine or non-routine calibration adjustments at the various calibration gas levels (zero, mid, or high), but no other corrective maintenance, repair, re-linearization or reprogramming of the monitor is allowed. Trial gas injection runs may be performed after the calibration adjustments prior to the linearity check to optimize the performance of the monitor. The trial gas injections do not have to be reported provided they meet the specification for trial gas. However, if this specification is not met, the *trial injection will be counted as an aborted linearity check.*

The linearity check may be done after repair, corrective maintenance or reprogramming of the monitor. In this case, the monitor will be considered out-of-control from the hour of the repair, corrective maintenance, or reprogramming was performed until the hour of a successful linearity check. Alternately, the data validation procedures and associated timelines may be followed when the repair, corrective maintenance, or reprogramming of the monitor has been completed.

Once the linearity check has been started, no adjustments of the monitor are permitted during the test period other than routine calibration adjustments.

If a daily calibration error test failed during a linearity test period, prior to completing the test, the linearity check must be re-started. Data from the monitor are invalidated from the hour of the failed calibration error test until the hour of a successful calibration error test. The linearity error check cannot be re-started until a successful calibration error test has been completed.

For each monitoring system, report results of all completed and partial linearity tests that affect data validation in the required quarterly report. Linearity attempts that were aborted because of problems with the calibration gases or plant operational problems do not need to be reported. A record of all linearity tests, trail gas injections and test attempts (reported or unreported) must be kept on-site as part of the official test log for each monitoring system.

No more than four successive calendar quarters shall elapse after the quarter in which a linearity check was last performed without conducting a subsequent linearity test. If a linearity test has not been completed by the end of the fourth calendar quarter since the last linearity test, then the linearity test must be completed within a 168-unit operating hour grace period following the end of the fourth successive elapsed calendar quarter. Otherwise, data collected by the monitoring system will be considered invalid.

6.4.4 Linearity Error Grace Period

When a required linearity test has not been completed by the end of the QA operating calendar quarter in which it is due, or because of infrequent operation of a unit, infrequent use of a required high range monitor or monitoring system, four successive calendar quarters have elapsed after the quarter in which a linearity was last performed, the owner/operator has a grace period of 168 consecutive operating hours in which to perform the linearity test. The grace period starts with the operating hour following the calendar quarter in which the linearity test was due.

If at the end of this 168-unit operating hour grace period, the required tests have not been performed, data from the monitoring system will be considered invalid beginning with the hour of the missed 168 hour grace period. Data from the monitoring system will remain invalid until the hour of completion of a subsequent successful hands-off linearity test. A linearity test performed within a grace period satisfies the QA requirements for the missed quarter but not for the quarter that the grace period linearity test was completed.

6.4.5 Out-of-Control Period

An out-of-control period occurs when the error in linearity at any of the three concentrations (six for dual range) exceeds the applicable specifications of >5% error. The out-of-control period begins with the hour of the failed linearity check and ends with the hour of a satisfactory linearity check following the corrective action. During the time the CEMS is out-of-control the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.

6.5 Annual Assessments

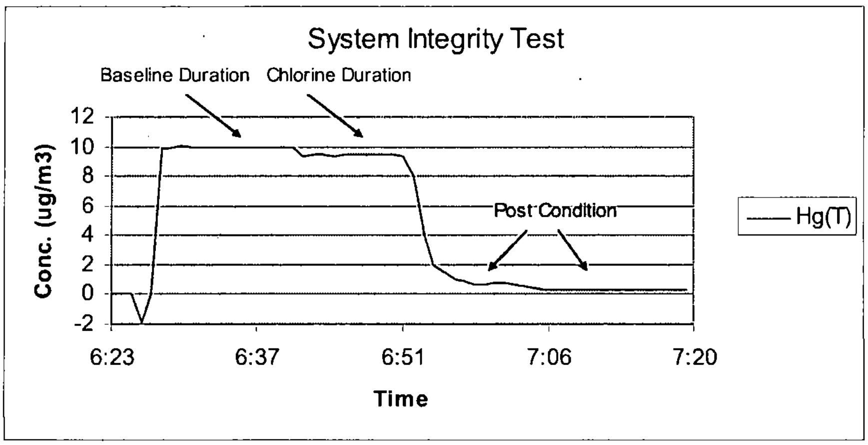
EPA Test Method 30B is used as the Reference Method for certification of the Hg monitoring system. Method 30B is a procedure for measuring total vapor phase mercury (Hg) emissions from coal-fired combustion sources using sorbent trap sampling and an extractive or thermal analytical technique. Alternatively an EMPA Test Method 30A is also a valid Reference Method which may be chosen in lieu of a 30B RATA.

An annual RATA will be conducted. The error limit for an annual RATA is +/ 1.0 µg/scm

6.6 System Integrity Check

The system integrity check measures the ability of the probe converter to reduce mercuric chloride to elemental mercury. In order to test this in a controlled manner, a process is needed to generate a known quantity of oxidized mercury, in this case mercuric chloride.

During a system integrity check, the system initially runs a baseline measurement by generating a known concentration of elemental mercury prior to introducing 900ppm chlorine. The suggested Hg baseline duration is 12 minutes. Chlorine duration is 15 minutes and post condition is 3 minutes.



Be sure that the metal orifice is connected to the output of the regulator. A regulated pressure of 10 psi will give a gas flow of approximately 330 cc/min. The table below compares chlorine pressures and expected flows.

NOTE: JEA does not currently perform the system integrity check due to equipment and vendor support issues. Furthermore, NIST has never completed traceability requirements for this test. This note is applicable to all references to the system integrity check, ionic calibrations, or any calibration performed using any gas other than elemental mercury which may be made elsewhere in this document.

Table 2 Chlorine Pressures and Expected Flows

Chlorine Pressures and Expected Flows	
Regulator pressure (psi)	**Gas flow (cc/min)**
5	190
10	330
15	440
20	540
25	640

A dilution occurs since we are adding chlorine gas to the span gas. A dilution factor should be multiplied by the oxidized concentration readings. The dilution factor equation is as follows:

$$(81i\text{ flow} + Cl_2\text{ flow})\ 81i\text{ flow}$$

Where: The 81i flow equals the Measured Dilution Flow during a System Integrity test. This reading is found in the Diagnostics > Flow menu in the 81i.

This equation, when multiplied by the Hg(T) reading (during the Chlorine Duration step) will give accurate concentration readings while the chlorine is ON.

Note The Hg baseline reading preceding the chlorine duration should not be multiplied by this factor. ◈

The System integrity calculation measures how well the system can measure oxidized mercury (expressed as a percentage). The calculation is as follows:

100 * Hg(T) reading at the end of the chlorine duration * chlorine dilution factor Hg(T) baseline

Chapter 7.0 ROUTINE PREVENTIVE MAINTENANCE

Routine preventative maintenance actions, descriptions, and schedules can be found in Section 5.0 Quality Control Activities.

7.1 Preventive Maintenance Forms

This section contains a suggested form for performing preventive maintenance. Maintenance schedules may vary depending upon site-specific conditions (i.e., filters may need to be changed more often in a "dirty" environment or less often under "clean" conditions). For detailed maintenance, procedures refer to the manufacturer's instruction manuals and other technical data included separate cover.

Some items, such as filter checks, may not exhibit a failure condition until damage has occurred to other components. Initially, these items will require careful and frequent checking to determine replacement frequency specific to individual applications. Any changes of the operating characteristics of the system should trigger a maintenance response to prevent loss of data and/or equipment damage. This includes paying attention to any shift (sudden or prolonged) in one direction and close observation of the visual indicators in the system.

CEMS alarms indicate that service is required. They do not necessarily indicate that the collected data is invalid. The alarms do indicate that the system is operating outside of design tolerance and incorrect data and equipment damage will occur if the system continues operation without corrective action. For this reason, the alarms themselves should be tested on a regular basis to assure that they are operating as designed. All alarm conditions require quick attention and resolution.

Form 7-1: Quarterly Preventive Maintenance Check

Unit No.: ________ Date: ____________

Mercury System			
Check all desiccant (Dryrite, Carbon, Purafil) .			
Mercury-Model 80i			
1. Clean outside of case 2. Visual inspection and clean 3. Critical orifice inspection (qty 2) 4. Inspect fan filter 5. Check lamp voltage/frequency check			
Mercury-Model 81i			
1. Clean outside of case 2. Inspect and clean chiller fins 3. Inspect and clean fan filter			
Mercury-Model 83			
1. Clean inertial filter with brush 2. Inspect and clean chiller fins			
Mercury-Hydrator & Heated Umbilical			
1. Perform Hydrator functional test as per Manufacturer 's manual .			
Welch Vacuum Pump			
1. Rebuild Vacuum Pump			

Form 7-2: Semi-Annual Preventive Maintenance Check

Unit No.: __________ Date: ________________

ITEM	Initials	Record values	Comments
Mercury-System			
1. Replace Dryrite, Carbon & Purafil. 2. Filter for black canister 3. Pump replacement as needed			
Mercury-Model 81			
1. Perform leak test 2. Replace scrubbers			
Mercury-Model 83			
1. 15 micron filter 2. Thermocouple converter 3. Preventative maintenance kit			

Example Form 7-3: Annual Preventive Maintenance Check

Unit No.: __________ Date: ______________

ITEM	INITIALS	RECORD VALUES WHERE APPLICABLE	COMMENTS
Model 80			
Leak Test			
Replace analyzer lamp			
Model 81			
Leak Test			
Replace scrubbers			
Model 83			
15 micron filter			
Thermocouple converter			
Preventative maintenance kit			
–System			
Cleaning sample lines (2)			
Replace Dryrite			
Replace carbon			
Replace Purafil			
Filter for black canister (Cl)			
Pump replacement as needed			

Chapter 8.0 CORRECTIVE MAINTENANCE

This section contains information on performing troubleshooting and corrective maintenance. For detailed procedures refer to the manufacturer's instruction manuals and other technical data included under separate cover. The Technician should be familiar with the material in these manuals before attempting any troubleshooting.

8.1 Objectives of the CEMS Corrective Action Program

The objectives of the Northside Generating facility Corrective Action program are to:

- Identify and report CEM systems problems at the earliest stage of development.
- Correct or otherwise address CEM systems problems in a timely manner in order to minimize the impact of these problems.
- Identify and eliminate the root causes of the problems, where appropriate, in order to prevent the same type of problems from arising in the future.
- Establish guidelines for responding to problem situations in a manner which contributes to the probability of making correct decisions and minimizes possible legal consequences.
- Define lines of communication to management in order to facilitate management's role in reducing the frequency of problems and insuring the adequacy and timeliness of corrective actions.

The implementation of each of these objectives is discussed below.

Identify and report CEM systems problems at the earliest stage of development

The Inspection/Maintenance Procedures discussed in Section 5, are designed to identify problems early in their development. Minor adjustments and corrections to the system are performed on a routine basis as part of the Daily/Weekly and Quarterly I/PM. When a non-routine or major problem is found, a more formal corrective action process should begin.

For the purposes of this program, a non-routine or major problem is one that causes or has the immediate potential to cause:

- The health or safety of employees or the surrounding community to be endangered;
- The facility to be non-compliant with local, state, or federal regulations;
- A loss of CEM data;
- An "out of control" condition to occur with one or more analyzers;
- Damage to the CEM systems or its components;
- A significant liability to JEA Northside Generating Station.

The Corrective Action Program is initiated with an entry into the Ops Log. This report is completed by the person who discovers the problem or area of concern. It is logged into the Ops Log sytem which maintains the record of all such reports. Reports shall be kept for at least five years. All employees are required to use Ops Log if a problem situation or area of concern is identified.

Once a corrective action is completed, I&C Technician evaluates the results in order to determine if the action is effective. If not, the action/evaluation cycle continues until an effective solution is found.

Initiation of corrective action and notification/reporting requirements are discussed in more detail in the objectives below.

Correct or otherwise address CEM systems problems in a timely manner in order to minimize the impact of these problems

The Plant Manager shall respond to each report within a time frame appropriate to the item in question. In all cases the response time will be ten days or less. The response shall consist of:

- reviewing the report;
- determining whether a corrective action is warranted;
- deciding on the nature and timing of such a corrective action;
- determining if intermediate measures are required;
- completing the Work Order;
- returning it to the Originator;
- filing the report in the ongoing Open Items file.

The response must be completed according to the instructions on the reverse of the form. Copies of each report shall be maintained in Records Office for a period of at least five years.

If the Plant Manager determines that a corrective action is necessary, the appropriate information shall be completed. Once the corrective action is completed, the Plant Manager shall evaluate the results in order to determine if the action is effective. If not, the action/evaluation cycle shall continue until an effective solution is found.

The Plant Manager may determine that intermediate measures are required to protect the health or safety of workers or the community, to maintain facility compliance, to prevent damage to the CEM systems or other assets, or to minimize any potential liability to the Northside Generating Station Facility. These measures must be listed in the appropriate section of the form. The Plant Manager has the responsibility to ensure that these measures are implemented and are effective.

Identify and eliminate the root causes of the problems, where appropriate, in order to prevent the same type of problems from arising in the future.

In some cases, a problem may be only a symptom of another more fundamental problem. Correcting the symptom without addressing the root problem may not be the best approach. B. W. Marguglio in his book "Environmental Management Systems" has suggested the following criteria be used to determine when the root cause of a problem should be addressed:

- When the problem can recur and adversely affect public and/or employee health and safety.
- When the problem can recur and any single recurrence will cost considerably more than the cost of identifying and correcting the root cause.
- When the problem has been recurring and is expected to continue to recur and the cumulative cost of future recurrences considerably exceeds the cost of identifying and correcting the root cause.
- When the problem can recur and cause political or regulatory embarrassment.

Unless the cost is significant, most root cause decisions do not require a detailed cost/benefit analysis. In many cases the root cause may be known or suspected and simple tests should determine the appropriate corrective action. In cases where significant time or money must be expended to determine the root cause or the appropriate corrective action, the Plant Manager will discuss the issues and costs with the Plant Manager. This discussion shall result in a corrective action decision which will be implemented and monitored by the Plant Manager.

Establish guidelines for responding to problem situations in a manner which contributes to the probability of making correct decisions and minimizes possible legal consequences.

- *Timeliness* - The Environmental Services Coordinator is responsible for evaluating each situation as it occurs and determining an appropriate response time. In the absence of the Environmental Services Coordinator this task falls to the Maintenance Supervisor.
- Proper Individual - It is important that the individual assigned to implement the corrective action be qualified. A comprehensive and on-going training program extends the skills and expertise of the employees and increases the probability that the right person can be found. It is also important to recognize when the appropriate expertise is not available "in-house." A current list of outside contractors should be maintained for quick reference when this situation arises.
- *Systematic Approach* - A "gut-feel" or haphazard approach to identifying problems and solutions is not an acceptable methodology. Standard Operating Procedures have been developed to ensure that thorough and systematic methods are used. It is important that these SOPs be continually updated and that new SOPs are developed as operators become more familiar with the CEM systems and its unique characteristics.
- *Test Effectiveness of Solutions* - At the conclusion of each corrective action procedure, an evaluation should be performed to determine if the corrective action was effective. The Work Order includes a section that addresses this requirement.
- *Proper Documentation* - Since all of the information regarding the CEM systems is being audited by state and federal regulatory agencies, it is essential to maintain a "paper trail" of all actions and decisions on this system. The Maintenance Log and the CEM systems Work Order are the key elements in establishing this paper trail. These documents must be completed and archived on a routine basis.

Define lines of communication to facilitate management's role in reducing problem frequency and insuring the adequacy and timeliness of corrective actions.

Each week, the Environmental Services Coordinator shall submit copies of all pending and recently finalized report to the Plant Manager for closure and filing. The I&C Technician will also submit any supplemental information that will assist the Environmental Services Coordinator in the review of the material.

The Environmental Services Coordinator shall review these reports in order to ensure that:

- Corrective action decisions are adequate and do not expose the Northside Generating Station Facility to increased liability;
- Corrective action activities are proceeding according to schedule;
- Root cause decisions are made where appropriate;
- Corrective actions are effective.

If the Plant Manager finds that any of these items are of concern, he will address those with the Plant Manager.

8.2 Troubleshooting the Mercury Freedom™ System

Please refer to the Mercury Freedom™ System Operating Manual for Troubleshooting items and actions.

Chapter 9.0 Data Validation and Reporting

9.1 Record Keeping

General record keeping requirements for continuous emissions monitoring systems are detailed in this plan. ***Records should be kept on site of all start-up/shutdown operations, malfunctions, measurements, data, reports, audits and maintenance logs for at least 3 years from the date the record was created.*** These records should be kept in an organized manor suitable for inspection by U.S. EPA representatives.

9.1.1 Responsible Individual

The Environmental Services Coordinator is responsible for maintaining all required records of the CEMS system in a central location known to all responsible individuals.

NOTE:

Records should be kept in a central location known to all responsible individuals in this QA/QC Plan. These files should be made available to representatives of the United States EPA with proper identification upon demand.

9.1.2 Records Required

This list includes all data and records required to comply with the quarterly reporting requirements, and this QAP.

On a quarterly basis, the designated representative (DR) must certify the accuracy and completeness of all CEMS records submitted, including the CEMS quarterly reports. In order to make this certification, the DR should receive *copies* of the following CEMS records:

- Linearity Test Reports (written)
- Quarterly Maintenance Checklists and Log sheets (written)
- Quarterly CEMS Report (electronic)

9.1.3 Notifications

JEA will follow these guidelines for notification and submittals for the mercury CEMS.

Table 9-1:
Notification Requirements

Type of Notification	Notification Requirements
Initial Certification & Recertifications	21 days in writing prior to testing. (see note)
Recertifications after initial certification	21 days in writing and/or phone prior to testing. (see note)

New Units and Stacks -- If planned date changes	45 days in writing prior to commercial operation and/or when stack exhausts emissions. 7 days in writing and/or phone following planned commercial operation and stacks exhausting to the atmosphere.
Planned unit shutdown on compliance data & postpone certification testing	45 days in writing of planned shutdown & recommencement.
Unplanned unit shutdown	7 days in writing after shutdown.

9.1.4 Reporting

JEA will follow these guidelines for notification and submittals for the mercury CEMS.

Table 9-2:
Required Reports

Type of Report	Report Due date	Format
Initial Certification	Within 45 days after certification test	Current agency requirements
Recertifications	Within 45 days after recertification test	Current agency requirements
Quarterly Reports	Within 30 days after end of each calendar quarter	As specified by the Operating Permit requiremetns.
Annual Compliance Certification	Due March 1	Written
Excess Emissions	Not specified by regulations or permit conditions.	

A description of each of these reports is found in the following sections:

9.1.5 Certification and Recertification Test Reports

These reports must be submitted after completing the certification tests. Check with Administrator and Regional EPA office regarding whether electronic format, hardcopy format or both are required. The reports should include the following:

Results of all tests

- Results of DAHS accuracy confirmation
- Equations used

9.1.6 Quarterly Reports

Reports will be submitted as required by regulatory agencies. These reports contain the following information:

- Facility identification and location information;
- Unit operating hours for quarter and cumulative hours for year;
- Total heat input and integrated gross unit load for quarter and year;
- Facility representative affirmation;

Hourly operating parameters:

- Date/hour;
- Unit operating time;
- Gross load;
- Operating load range;
- Total heat input.

Daily gas analyzer calibration error checks:

- Component-system I.D.;
- Instrument span and span scale;
- Date/hour;
- Reference value in appropriate units;
- Monitor response (observed) value;
- Percent calibration error;
- Reference value or calibration gas level;
- Test number and reason for test.

Results of quarterly linearity checks:

- Component-system I.D.;
- Date/hour, minute of each injection;
- Instrument span and span scale;
- Calibration gas level;
- Reference value;
- Monitor response (observed) value;
- Mean of reference values;
- Percent linearity error at each of three levels;
- Test number and reason for test.

Monitoring Plans

The Regulations do not require a monitoring plan for the Mercury Freedom™ System CEMS analyzer.

Chapter 10.0 Certification and Recertification

10.1 Responsible Individual

The Environmental Services Coordinator is responsible for ensuring that the CEMS system certification is valid. The Environmental Services Coordinator is also responsible for reviewing CEMS analyzer changes; CEMS configuration changes, or changes to the location of the sample probe to determine if recertification testing may be required. The Environmental Services Coordinator is also responsible for all notification and testing required for CEMS recertification.

Table 10-1: Hg analyzer certification requirements

1.	7-Day Calibration Error Test	7 Day calibration error test will be performed in accordance with standard regulatory practices. No adjustments to the analyzer are allowed during the 7-day calibration period.
2.	Linearity Check	Will be performed according to standard regulatory practices
3.	Cycle Time Test	Use the minute data to determine the upscale and downscale response times as detailed in 40 CFR Part 75, Appendix A, section 6.4. Determine the upscale response time by plotting the analyzer response going from a zero- level concentration gas to 95% of the stable flue gas measurement. Determine the downscale response time by plotting the analyzer response going from a high-level concentration gas to 95% of the stable flue gas measurement.
4.	System Integrity Check	Will be performed in accordance with manufacturer recommendations
5.	Relative Accuracy Test	Will not be performed at this time.

10.2 Recertification Requirements

Whenever the operator makes a replacement, modification, or change in the CEMS (including the DAHS) *that significantly affects the ability of the CEMS to measure or record Hg*, the CEMS system or component must be recertified. Agency notification will follow such changes

Recertification is not required for changes resulting from routine or normal corrective maintenance, or the routine activities contained in this QA/QC Plan. Examples of changes requiring recertification include:

1. Analyzer replacements (i.e., *complete* analyzer removal and replacement).
2. Change in the placement, location or orientation of the sample probe, including ductwork changes in the vicinity of the sample probe.

The Environmental Services Coordinator should review any proposed changes to the flue gas ducts or stacks within 50 ft of the sample probe to ensure that these changes do not significantly affect the ability of the CEM system to measure Hg.

10.2.1 Notification

For recertification testing, the JEA will notify the agencies.

10.2.1.1

10.2.2 Analyzer Recertification Test Requirements

When a gaseous analyzer is recertified, the same tests are required as for initial certification.

10.2.3 DAHS Recertification Test Requirements

When a DAHS modification or change is made which affects the emissions calculations performed, recertify the DAHS using the U.S. EPA's DCAS software. In addition, a successful daily calibration of all systems containing that DAHS is required.

10.3 Diagnostics Tests

Changes to CEMS system components may require that QA tests be performed for diagnostics purposes. In such cases, the CEMS system or component is not being recertified, and the notification and testing requirements for recertification noted above do not apply.

Chapter 11.0 Recommended Spare Parts List

Please refer to the Mercury Freedom$_{TM}$ System Operating Manual for the spare parts list.

Chapter 12.0 COMMONLY USED EQUATIONS

12.1 CEM Accuracy by Linearity Check (Quarterly Audit):

Accuracy determined by linearity error check is specific to each analyzer or channel for the three audit gases injected.

Equation:	Where:
$LE = \frac{\lvert R - A \rvert}{R} \times 100$ or for alternate criteria use $LE = \lvert R - A \rvert$	LE = Percent accuracy of the CEM. R = Calibration gas reference value. A = Average of monitor response

12.2 CEM Accuracy by RATA:

Equation:	Where:
Equation 6-4: RATA, Arithmetic Mean 40 CFR 75, Appendix A, Equation A-7	
$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i$	$\bar{d} = Arithmetic\ mean$ $n = Number\ of\ data\ points$ $\sum_{i=1}^{n} d_i = algebraic\ sum\ of\ the\ individual\ differences, d_i$
Equation 6-5: RATA, Standard Deviation 40 CFR 75, Appendix A, Equation A-8	
$S_d = \sqrt{\frac{\sum_{i=1}^{n} {d_i}^2 - \frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n^2}}{n-1}}$	$S_d = standard\ deviation$ $n = number\ of\ data\ points$ $\sum_{i=1}^{n} d_i = algebraic\ sum\ of\ the\ individual\ differences, d_i$
Equation 6-6: RATA, Confidence Coefficient 40 CFR 75, Appendix A, Equation A-9	
$cc = t_{0.025} \frac{S_d}{\sqrt{n}}$	$cc = confidence\ coefficient$ $S_d = standard\ deviation$ $n = number\ of\ data\ points$ $t_{0.025} = t\ value$

Equation 6-7: Relative Accuracy 40 CFR 75, Appendix A, Equation A-10	
$$RA = \frac{\lvert\bar{d}\rvert + \lvert cc\rvert}{\overline{RM}} \times 100$$	$RA = relative\ accuracy$ $\overline{RM} = arithmetic\ mean\ of\ the\ reference\ method\ values$ $\lvert\bar{d}\rvert = $ $the\ absolute\ value\ of\ the\ mean\ difference$ $between\ the\ reference\ method\ values\ and$ $the\ corresponding\ CEMS\ values$ $\lvert CC\rvert = $ $absolute\ value\ of\ the\ confidence\ coefficient$

12.2.1 Pollutant Analyzer and Flow Monitor Daily Calibration Error

Span Calibration Fail	
Equation:	**Where:**
$$S_d = \frac{\lvert S_b - S_r \rvert}{FS} \times 100$$ $S_d \geq \text{Setpoint} = \text{Calibration Fail}$	S_d = Span drift in percent (upscale drift.) S_r = Span reading (upscale actual.) S_b = Span bottle value, (calibration variable) (upscale expected.); high reference value for flow monitors FS = Analyzer full-scale value in ppm (for diluent, FS = 100.) Setpoint = 2 x PS (performance standard) for 1 day calibration fail. Setpoint = 4 x PS (performance standard) for 1 day calibration fail.
Zero Calibration Fail	
$$Z_d = \frac{\lvert Z_b - Z_r \rvert}{FS} \times 100$$ $Z_d \geq \text{Setpoint} = \text{Calibration Fail}$	Z_d = Zero drift in percent. Z_r = Zero reading (zero actual.) Z_b = Zero bottle (typical 0.0) (zero expected.); low reference value for flow monitors FS = Analyzer fullscale value, ppm (for diluent, FS = 100.) Setpoint = 2 x PS (performance standard) for 1 day calibration fail. Setpoint = 4 x PS (performance standard) for 1 day calibration fail.

12.2.2 Diluent Analyzer Calibration Drift

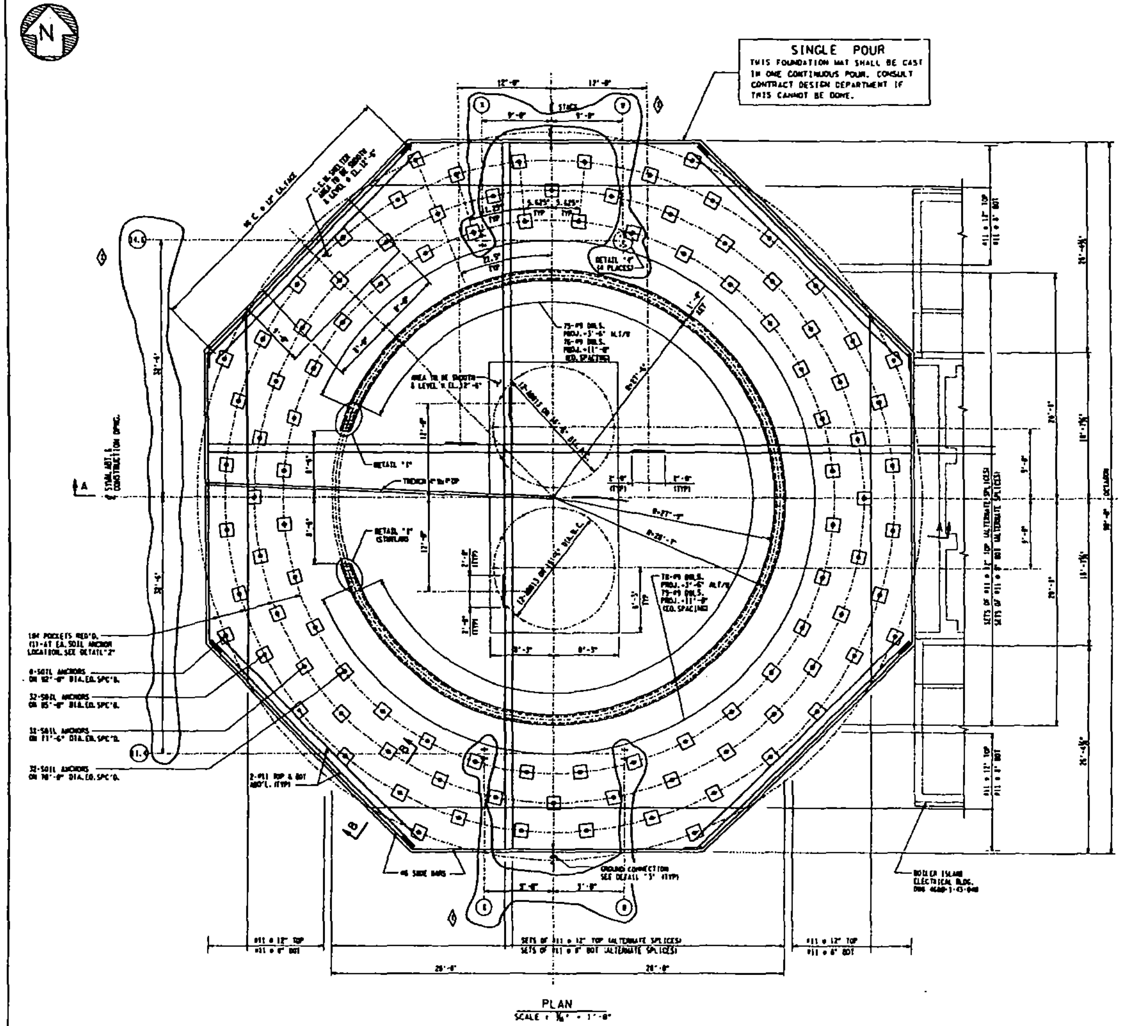
Span Calibration Fail		
Equation:	**Where:**	
$S_d = \lvert S_b - S_r \rvert$ $S_d \geq$ Setpoint = Calibration Fail	S_d =	Span drift, percent (upscale drift.)
	Sr =	Span reading (upscale actual.)
	S_b =	Span bottle value, (calibration variable) (upscale expected.)
	FS =	Analyzer fullscale value in ppm (for diluent, FS = 100.)
	Setpoint =	2 x PS (performance standard) for 1 day calibration fail.
	Setpoint =	4 x PS (performance standard) for 1 day calibration fail.
Zero Calibration Fail		
$Z_d = \lvert Z_b - Z_r \rvert$ $Z_d \geq$ Setpoint = Calibration Fail	Z_d =	Zero drift in percent.
	Zr =	Zero reading (zero actual.)
	Sb =	Zero bottle (typical 0.0) (zero expected.)
	FS =	Analyzer fullscale value, ppm (for diluent, FS = 100.)
	Setpoint =	2 x PS (performance standard) for 1 day calibration fail.
	Setpoint =	4 x PS (performance standard) for 1 day calibration fail.

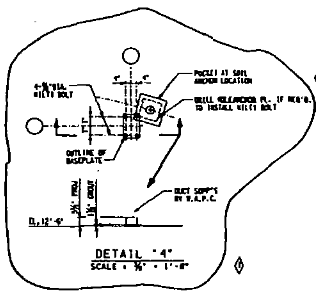
Chapter 13.0 Attachments

Attachment A - Air Operating Permit

Attachment B – Stack Drawings

4600-1-43-027





GENERAL NOTES:

1. FOR GENERAL NOTES & REFERENCE DRAWINGS SEE DWG. 4600-1-43-100.
2. ALL ELEVATIONS ARE PER N.G.V.D. (NATIONAL GEODETIC VERTICAL DATUM).

BILL OF MATERIAL	
QUANTITY	DESCRIPTION
1740	CUBIC YARDS CONCRETE [illegible] 4000 P.S.I. @ 28 DAYS
1	LOT REINFORCING RODS
24	ANCHOR BOLTS A[illegible]13
[illegible]	SQ.FT. 6x6-W2.9xW2.9 WELDED WIRE FABRIC
16	3/4" DIA. HILTI BOLTS

WORK THIS DRAWING WITH DWG. 4600-1-43-028

JEA

Northside Units 1 & 2 Repowering Project

EQUIPMENT No.: [illegible]

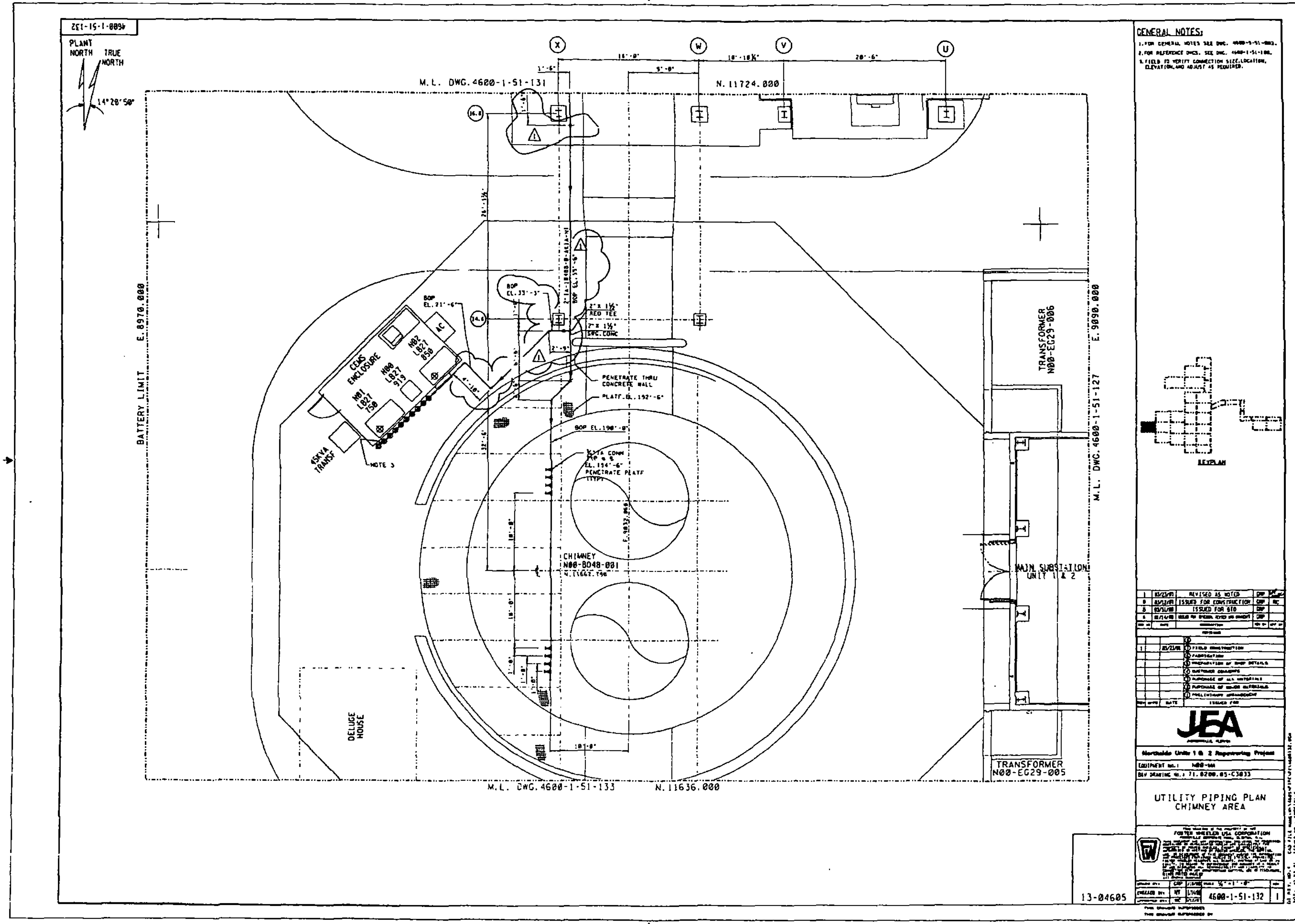
B&V DRAWING No.: B&V DWG NO [illegible]

FOUNDATION PLAN
STACK FG-ST-201

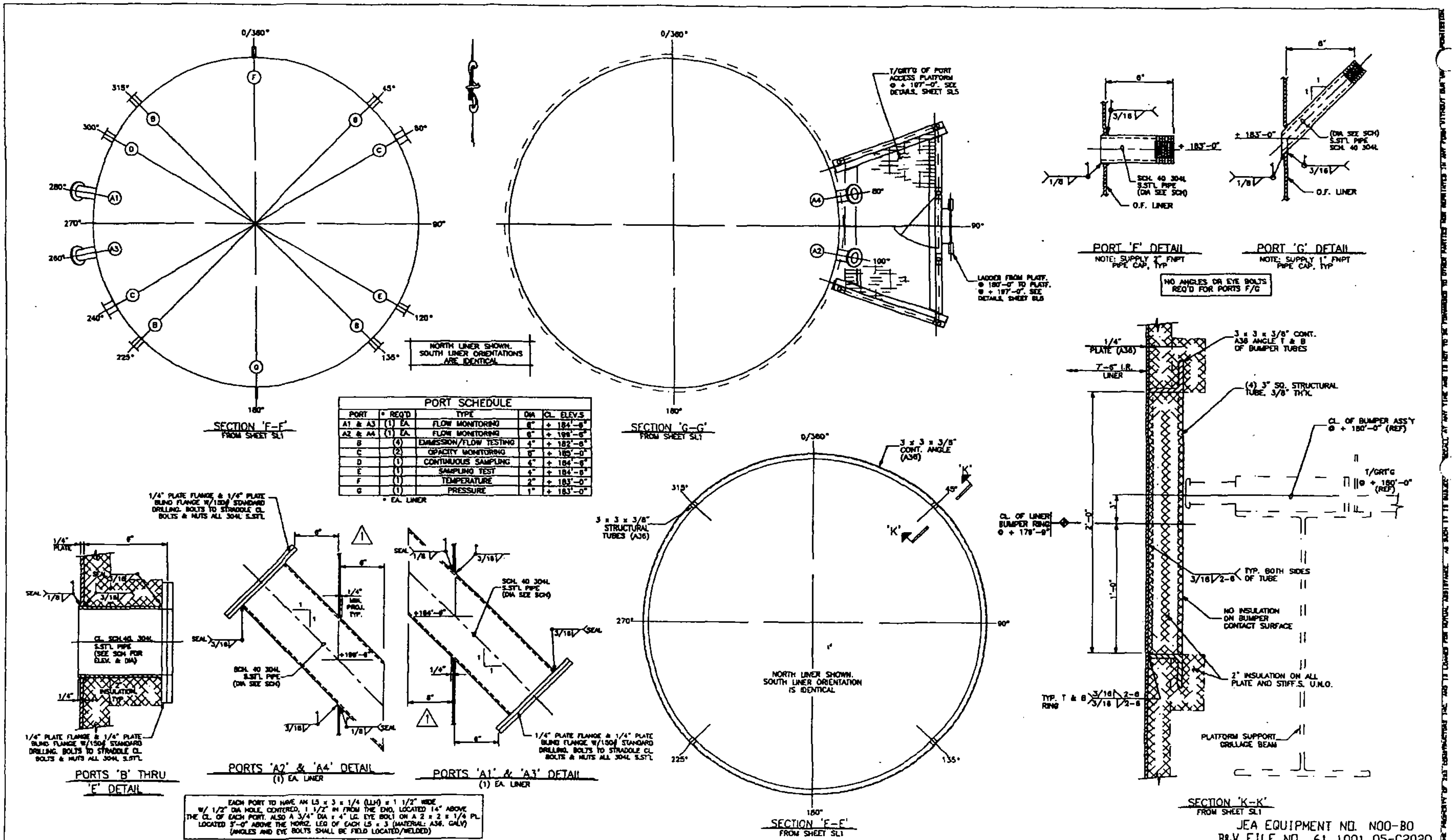
FOSTER WHEELER USA CORPORATION

4600-1-43-027 | 1

135418


4600-1-51-132
PLANT NORTH
TRUE NORTH
14°20'50"
M.L. DWG.4600-1-51-131
N.11724.000
M.L. DWG.4600-1-51-133
N.11636.000
BATTERY LIMIT
E.8970.000
E.9090.000
M.L. DWG.4600-1-51-127
CEMS ENCLOSURE
AC
45KVA TRANSF
NOTE 3
BOP EL.21'-6"
BOP EL.33'-3"
2"x 1½" RED TEE
2"x 1½" ECC.CONC
PENETRATE THRU CONCRETE WALL
PLATF.EL.192'-6"
BOP EL.190'-0"
PENETRATE PLATF (TYP)
CHIMNEY
N00-B040-001
TRANSFORMER N00-EG29-006
MAIN SUBSTATION UNIT 1 & 2
TRANSFORMER N00-EG29-005
DELUGE HOUSE
GENERAL NOTES:
KEYPLAN
REVISED AS NOTED
ISSUED FOR CONSTRUCTION
ISSUED FOR BID
FIELD CONSTRUCTION
JEA
Northside Units 1 & 2 Repowering Project
B&V DRAWING No. 71.0200.05-C3033
UTILITY PIPING PLAN
CHIMNEY AREA
FOSTER WHEELER USA CORPORATION
13-04605
4600-1-51-132

135467



PORT SCHEDULE				
PORT	* REQ'D	TYPE	DIA	CL. ELEV.S
A1 & A3	(1) EA.	FLOW MONITORING	6"	+ 184'-6"
A2 & A4	(1) EA.	FLOW MONITORING	6"	+ 199'-6"
B	(4)	EMMISSION/FLOW TESTING	4"	+ 182'-6"
C	(2)	OPACITY MONITORING	6"	+ 185'-0"
D	(1)	CONTINUOUS SAMPLING	4"	+ 184'-6"
E	(1)	SAMPLING TEST	4"	+ 184'-6"
F	(1)	TEMPERATURE	2"	+ 183'-0"
G	(1)	PRESSURE	1"	+ 183'-0"

* EA. LINER

JEA EQUIPMENT NO. N00-80
B&V FILE NO. 61.1001.05-C2020

NO.	DATE	BY	APP'D	REVISION
1	1/18/00	GJT	TH	REVISED PER CUSTOMER COMMENTS

ISSUED FOR	DATE	BY
"AS-BUILT"	11/7/00	GJT
CONSTRUCTION	1/25/00	GJT
REVIEW	1/3/00	GJT

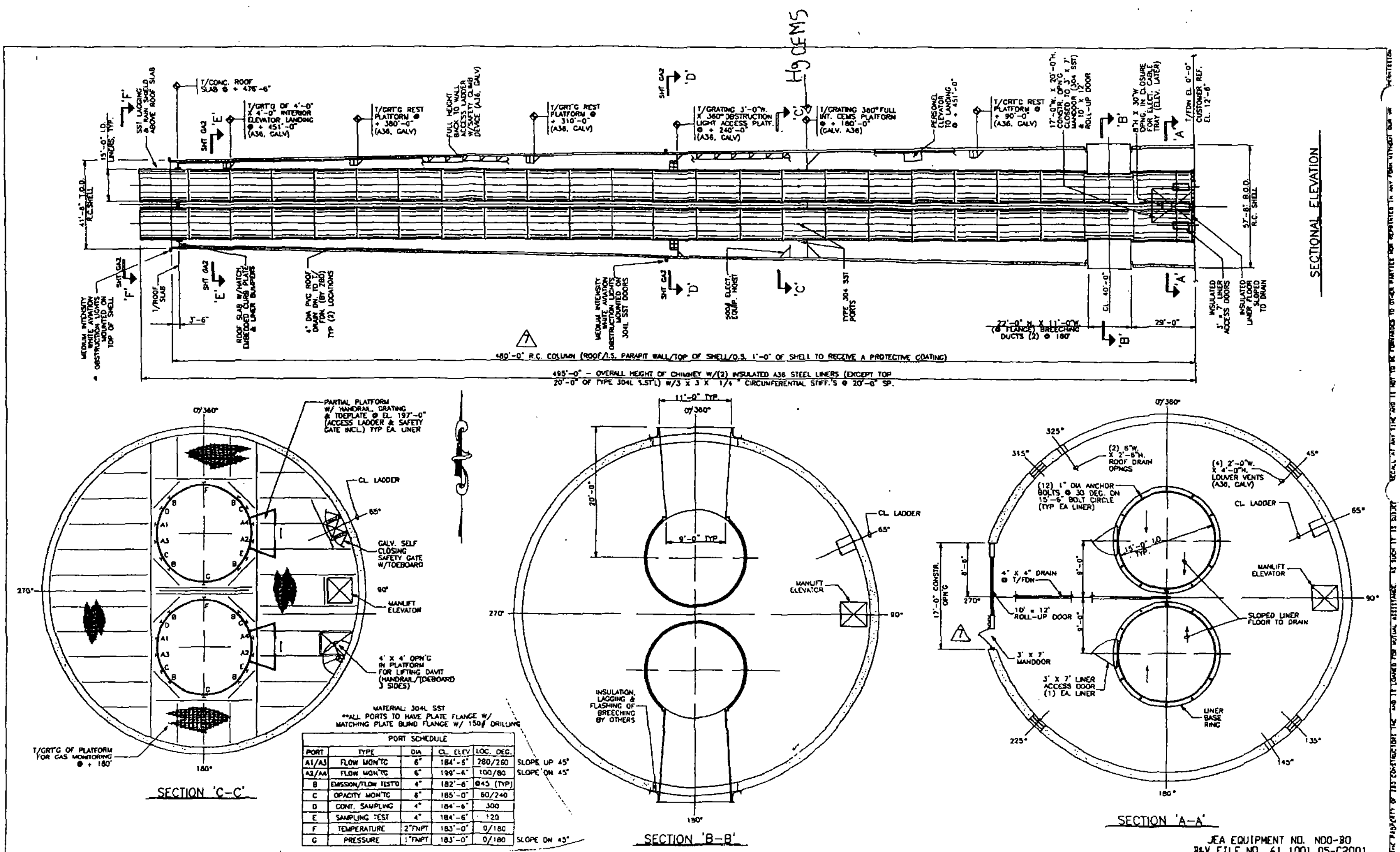
CONCRETE CHIMNEY W/(2) STEEL LINERS
JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE UNITS 1 & 2
REPOWERING PROJECT
JACKSONVILLE, FLORIDA
FOSTER WHEELER USA CORP.
ZBD PROJECT NUMBER 2051

ZBD CONSTRUCTORS INC.

DRAWING TITLE: STEEL LINERS - SHEET 3
PORTS AND MID LEVEL BUMPERS

CHECKED ELY
REV. 2
DWG. NO. SL3

106510



MATERIAL: 304L SST
**ALL PORTS TO HAVE PLATE FLANGE W/ MATCHING PLATE BLIND FLANGE W/ 150# DRILLING

PORT SCHEDULE					
PORT	TYPE	DIA	CL ELEV	LOC. DEG.	
A1/A3	FLOW MON'TG	6"	184'-6"	280/260	SLOPE UP 45°
A2/A4	FLOW MON'TG	6"	199'-6"	100/80	SLOPE DN 45°
B	EMISSION/FLOW TESTG	4"	182'-6"	@45 (TYP)	
C	OPACITY MON'TG	8"	185'-0"	60/240	
D	CONT. SAMPLING	4"	184'-6"	300	
E	SAMPLING TEST	4"	184'-6"	120	
F	TEMPERATURE	2"FNPT	183'-0"	0/180	
G	PRESSURE	1"FNPT	183'-0"	0/180	SLOPE DN 45°

JEA EQUIPMENT NO. N00-B0
B&V FILE NO. 61.1001.05-C2001

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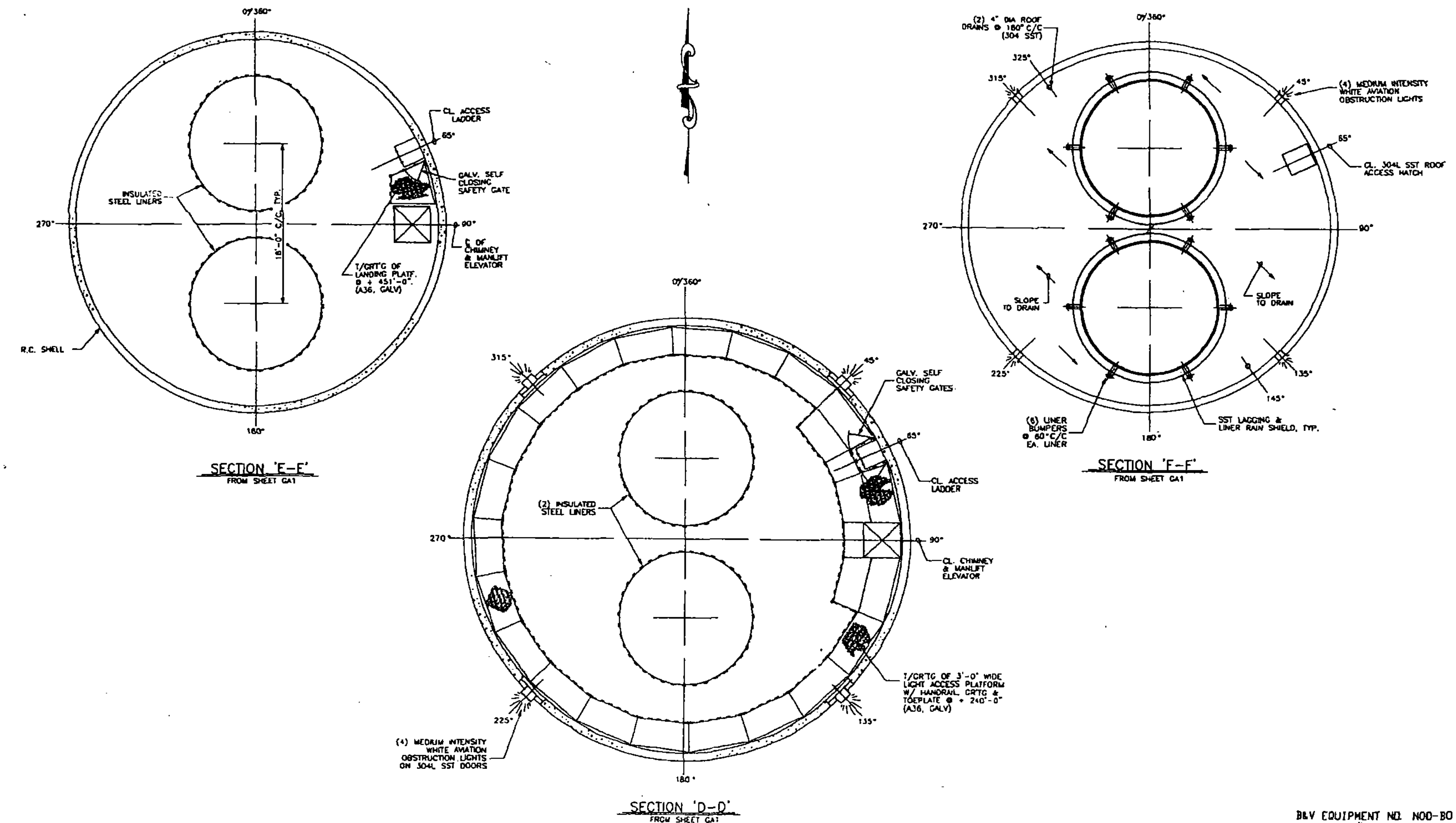
					3	[illegible]	GJT	TH	REVISED PER CUSTOMER COMMENTS	"AS-BUILT"	11/7/00	GJT	RECORD	11/11/99	GJT
6	[illegible]	GJT	TH	REVISED PER CUSTOMER COMMENTS	2	[illegible]	GJT	TH	REVISED PER CUSTOMER COMMENTS	RECORD	1/25/00	GJT	RECORD	10/20/99	GJT
5	[illegible]	GJT	TH	REVISED PORT LOCATIONS AS SHOWN	1	[illegible]	GJT	TH	REVISED PER CUSTOMER COMMENTS	RECORD	12/9/99	GJT	REVIEW	9/17/99	GJT

CONCRETE CHIMNEY W/(2) STEEL LINERS
JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE UNITS 1 & 2
REPOWERING PROJECT
JACKSONVILLE, FLORIDA
FOSTER WHEELER USA CORP.
ZBD PROJECT NUMBER 2051

ZBD CONSTRUCTORS INC.

DRAWING TITLE: GENERAL ARRANGEMENT
SHEET # 1

DRAWN R. MILLER | DATE 9/2/99
CHECKED CLV | DATE [illegible]
APPRVD RAP | DATE [illegible]
SCALE NONE | DWG SIZE 24x36
REV. 7
DWG NO GA1



B&V EQUIPMENT NO. NOO-BO
B&V FILE NO. 61. 1001. 05-C2002

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													RECORD	11/11/99	GJT			
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					2		GJT	TM	REVISED PER CUSTOMER COMMENTS	"AS-BUILT"	11/7/00	GJT	REVIEW	9/17/99	GJT			
NO	DATE	BY	APPD	REVISION	NO	DATE	BY	APPD	REVISION	ISSUED FOR	DATE	BY	ISSUED FOR	DATE	BY			

CONCRETE CHIMNEY W/(2) STEEL LINERS
JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE UNITS 1 & 2
REPOWERING PROJECT
JACKSONVILLE, FLORIDA
FOSTER WHEELER USA CORP.
ZBD PROJECT NUMBER 2051

ZBD CONSTRUCTORS INC.

DRAWING TITLE: GENERAL ARRANGEMENT SHEET # 2

CHECKED ELY
REV 4
DWG NO GA2

106402

Attachment C – Manufacturer Equipment Manuals

APPENDIX I

LIST OF INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

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

Brief Description of Emissions Units and/or Activities:

I. Northside Generating Station (NGS).

A. Storage Tanks.

1. JEA Tank	Magnesium Oxide	9,600 gallons
2. JEA Tank	Petrolite	6,500 gallons
3. JEA Tank	Lube Oil - Unit 1	10,000 gallons
4. JEA Tank	Lube Oil - Unit 2	10,000 gallons
5. JEA Tank	Mineral Acid	11,500 gallons
6. JEA Tank	Mineral Acid	11,500 gallons
7. JEA Tank	Caustic - East	10,000 gallons
8. JEA Tank	Caustic - West	10,000 gallons
9. JEA Tank	Hypochlorite	12,000 gallons
10. JEA Tank	Hypochlorite	12,000 gallons
11. JEA Tank	Lube Oil	18,000 gallons
12. JEA Tank	Lube Oil	7,000 gallons

II. St. Johns River Power Park (SJRPP).

A. AQCS Emergency Generator.

1. The emergency generator has historically fired less than 10,000 gallons per year of diesel fuel. The emergency generator draws its fuel from a single diesel fuel oil storage tank (the fuel oil has a maximum fuel sulfur content limit of 0.76%, by weight).

B. Power Block Emergency Generator.

1. The emergency generator has historically fired less than 10,000 gallons per year of diesel fuel. The emergency generator draws its fuel from a single diesel fuel oil storage tank (the fuel oil has a maximum fuel sulfur content limit of 0.76%, by weight).

C. Storage Tanks.

1. JEA Tank	Lube Oil	10,000 gallons
2. JEA Tank	Lube Oil	18,000 gallons
3. JEA Tank	Sulfuric Acid	6,000 gallons
4. JEA Tank	Sulfuric Acid	10,000 gallons
5. JEA Tank	Sulfuric Acid	6,000 gallons

6. JEA Tank	Sulfuric Acid	6,000 gallons
7. JEA Tank	Caustic	10,000 gallons
8. JEA Tank	Caustic	6,000 gallons
9. JEA Tank	Hydrazine	6,000 gallons
10. JEA Tank	Hypochlorite	6,000 gallons
11. JEA Tank	Anhydrous Ammonia	79,390 gallons
12. JEA Tank	Anhydrous Ammonia	79,390 gallons
13. JEA Tank	Hypochlorite	5,000 gallons
14. JEA Tank	Hypochlorite	5,000 gallons
15. JEA Tank	Hypochlorite	3,000 gallons

III. <u>NGS Boiler No. 1, NGS CFB Boilers Nos. 1 and 2, and SJRPP Boilers Nos. 1 and 2</u>.

1. Evaporation of on-site generated boiler non-hazardous cleaning chemicals (cirtosolv and ammonia). This activity occurs once every three to five years or longer.

2. NGS CFB Boilers Nos. 1 and 2.

Receiving, Storage and Reclamation of Fuel Additives. The facility is allowed to receive, store and reclaim fuel additives for usage in the CFB Boilers Nos. 1 and 2 to prevent agglomeration of the bed material in the boilers. The fuel additives, such as naturally occurring clays containing kaolinite or montmorillonite, along with olivine, bauxite or granite in the form of a raw material and/or as a component of coal bottom ash, will be delivered by conveyor belts to the fuel bunkers for storage prior to being fed into the boilers, where the projected usage is less than 100 tons per day per boiler.

Two Quonset huts (huts; one for each dome with dimensions of 35 feet wide, 50 feet long and 21 feet high) will be installed for storage purposes, with access only from one end to avoid wind erosion issues. They will be located near an entrance into each dome to minimize travel distance to the fuel conveyor system located inside each dome. The fuel additives will be brought in by covered trucks, at about 25 tons per load, and dumped into the Quonset hut opening prior to being moved further back into the storage hut using a front-end loader. After storage, the fuel additives will be reclaimed by a front-end loader and taken inside the dome for loading onto the fuels's conveyor belt. A front-end loader or similar equipment will be used to keep the roadway surfaces clean of any spilled materials. A water truck or vacuum street sweeper will be used to clean the roadways daily or as needed to suppress unconfined PM emissions from any spilled materials that were not removed by the front-end loader.

IV. <u>Solid Fuel Handling Facilities at the NGS and SJRPP</u>.

1. Solid fuel handling alternate operating scenario with capability to transport, using trucks, solid fuels (coal and petroleum coke) between the respective solid fuel handling facilities at NGS and SJRPP in the event of equipment failure, fuel delivery disruption or disproportionate fuel inventory.

V. <u>SJRPP Removal of Landfilled Ash.</u>

1. Future anticipated activities at SJRPP include the removal of landfilled ash for use off-site. A front-end loader will be used to dig the ash up and load the material directly on licensed dump trucks, which will haul the ash off-site. The stockpiled ash is expected to be moist and dust free.

VI. <u>NGS Limestone Feed System Fabric Filter Vents (6)</u>.

1. System is designed to collect limestone dust and return it to the limestone feed system. There are six emission points (baghouses). The process equipment is located between the limestone silos and the injection of limestone into the CFBs.

VII. <u>SJRPP Emergency Diesel Fire Pump</u>.

1. This equipment falls under the category of fire and safety equipment pursuant to Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions.

VIII. NGS By-Product Reclamation.
1. By-product reclamation at the by-product storage area (BSA). Fugitive particulate emissions will be minimized by using storage enclosures and dust suppression sprays/wetting agents.

IX. NGS Emergency Generator.
1. This emergency generator will be limited to 500 hours per year operation per the definition of "emergency generator" at Rule 62-210.200, F.A.C.; in addition, the generator can be operated only when the primary power source for that facility has been rendered inoperable by an emergency situation.

X. NGS Black-Start Emergency Generators (2).
1. These black-start emergency generators will be limited to 500 hours per year operation per the definition of "emergency generator" at Rule 62-210.200, F.A.C.; in addition, the generators can be operated only when the primary power source for that facility has been rendered inoperable by an emergency situation.

XI. NGS Emergency Storage of Solid Fuel outside the Coal Domes.
1. During emergency situations and unscheduled outages, JEA will store up to 20,000 tons of solid fuel in a bermed location (100 x 200ft) adjacent to the existing fuel storage dome for up to 3 weeks. Any runoff from this area will be collected within the berm and pumped by vacuum truck and placed in the on-site presedimentation basin thence to wastewater treatment facility. Water shall be applied, as necessary, to this area to control fugitive emissions. This temporary outside storage of solid fuel meets the reasonable precaution requirements for unconfined emissions of particulate matter and general visible emission requirements in accordance with Florida Administrative Code Rules 62-296.320(4)(c) and 62-296.320(4)(b) respectively.

XII. Two cooling towers for providing cooling for the air quality control systems at NGS.
1. The cooling towers are generically exempted in accordance with Rule 62-210.300(3)(b)(1), F.A.C.

XIII. SJRPP SCR Limestone System
1. The limestone system consists of limestone handling, conveying and storage and will be used for increasing the calcium content for some fuels to 5 percent in the ash and hence mitigate the potential contamination of arsenic.

XIV. Miscellaneous loading and unloading activities.
1. Miscellaneous loading and unloading activities, such as bringing in Kaolinite or other inert fuel additives by truck or rail, taking Byproduct Storage Area material out by truck or rail, and taking dry ash from the silos out by truck or rail.

XV. Other Insignificant Emissions Units and/or Activities.
1. Any other emissions unit or activity that:
   a. Is exempted from the requirement to obtain an air construction permit as cited in Rule 62-213.430(6)(a), F.A.C..

   And meets all of the following criteria pursuant to Rule 62-213.430(6)(b), F.A.C.:

   b. Is not subject to a unit-specific applicable requirement.
   c. In combination with other units and activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s) as defined by Rule 62-213.420(3)(c)1., F.A.C. unless acknowledged in a permit application.
   d. Would neither emit nor have the potential to emit:
      i. 500 pounds per year of lead and lead compounds expressed as lead;
      ii. 1,000 pounds per year or more of any hazardous air pollutant;
      iii. 2,500 pounds per year or more of total hazardous air pollutants; or
      iv. 5.0 tons per year or more of any other regulated pollutant.

GENERAL PROVISIONS

(version dated 10/9/2008)

E.U. ID No.	Brief Description
-016 & -017	SJRPP Boiler Nos. 1 & 2
-023	SJRPP: Fuel and Limestone Handling and Storage Operations
-026 & -027	NGS Circulating Fluidized Bed Boiler Nos. 2 & 1
-029	NGS: Crusher House Building Baghouse Exhaust
-031	NGS: Fuel Silos Dust Collectors
-033	NGS: Limestone Dryers/Mills Building
-034	NGS: Limestone Prep Building Dust Collectors
-035	NGS: Limestone Silos Bin Vent Filters

Federal Regulations Adopted by Reference

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

Federal Revision Date: June 13, 2007

Rule Effective Date: October 1, 2007

Standardized Conditions Revision Date: October 9, 2008

40 CFR Part 60, Subpart A - General Provisions

Index

End of Index

§ 60.1 Applicability.

(a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia. {Not Applicable}*

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading 'Department of Energy-Clean Coal Technology', up to a total amount of $2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Force majeure means, for purposes of §60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(3) Is equipped with low-NO_X burners prior to the time of commencement of operations following reactivation; and

(4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement: (1) The provisions of this part; and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

[44 FR 55173, Sept. 25, 1979, as amended at 45 FR 5617, Jan. 23, 1980; 45 FR 85415, Dec. 24, 1980; 54 FR 6662, Feb. 14, 1989; 55 FR 51382, Dec. 13, 1990; 57 FR 32338, July 21, 1992; 59 FR 12427, Mar. 16, 1994; 72 FR 27442, May 16, 2007]

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

kg—kilogram

m—meter

m^3 —cubic meter

mg—milligram—10^{-3}gram

mm—millimeter—10^{-3}meter

Mg—megagram—10^{6} gram

mol—mole

N—newton

ng—nanogram—10^{-9}gram

nm—nanometer—10^{-9}meter

Pa—pascal

s—second

V—volt

W—watt

Ω—ohm

μg—microgram—10^{-6}gram

(b) Other units of measure:

Btu—British thermal unit

°C—degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

°F—degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000

l—liter

lpm—liter per minute

lb—pound

meq—milliequivalent

min—minute

ml—milliliter

mol. wt.—molecular weight

ppb—parts per billion

ppm—parts per million

psia—pounds per square inch absolute

psig—pounds per square inch gage

°R—degree Rankine

scf—cubic feet at standard conditions

scfh—cubic feet per hour at standard conditions

scm—cubic meter at standard conditions

sec—second

sq ft—square feet

std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide

CO—carbon monoxide

CO_2—carbon dioxide

HCl—hydrochloric acid

Hg—mercury

H_2O—water

H_2S—hydrogen sulfide

H_2SO_4—sulfuric acid

N_2—nitrogen

NO—nitric oxide

NO_2—nitrogen dioxide

NO_X—nitrogen oxides

O_2—oxygen

SO_2—sulfur dioxide

SO_3—sulfur trioxide

SO_X—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

[42 FR 37000, July 19, 1977; 42 FR 38178, July 27, 1977]

§ 60.4 Address.

All addresses that pertain to Florida have been incorporated. To see the complete list of addresses please go to http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div6&view=text&node=40:6.0.1.1.1.1&idno=40.

Link to an amendment published at 73 FR 18164, Apr. 3, 2008.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection

Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 345 Courtland Street, NE., Atlanta, GA 30365.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(K) Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, FL 32301.

[40 FR 18169, Apr. 25, 1975]

Editorial Note: For Federal Register citations affecting §60.4 see the List of CFR Sections Affected which appears in the Finding Aids section of the printed volume and on GPO Access.

§ 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

[40 FR 58418, Dec. 16, 1975]

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)

(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974]

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

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

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with §60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by §60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by §60.8 in lieu of Method 9 observation data as allowed by §60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

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

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) shall both be submitted.

Figure 1—Summary Report—Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO_2/NO_X/TRS/H_2S/CO/Opacity)

Reporting period dates: From _____ to _____

Company:

Emission Limitation___________________

Address:

Monitor Manufacturer and Model No.___________________
Date of Latest CMS Certification or Audit___________________

Process Unit(s) Description:

Total source operating time in reporting period[1] ___________________

Emission data summary[1]		**CMS performance summary**[1]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	%[2]	3. [Total CMS Downtime] × (100) [Total source operating time]	%[2]

[1]For opacity, record all times in minutes. For gases, record all times in hours.

[2]For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Signature

____
Title

____
Date

(e)

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

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

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

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

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

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

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under

paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[36 FR 24877, Dec. 28, 1971, as amended at 40 FR 46254, Oct. 6, 1975; 40 FR 58418, Dec. 16, 1975; 45 FR 5617, Jan. 23, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 52 FR 9781, Mar. 26, 1987; 55 FR 51382, Dec. 13, 1990; 59 FR 12428, Mar. 16, 1994; 59 FR 47265, Sep. 15, 1994; 64 FR 7463, Feb. 12, 1999]

§ 60.8 Performance tests.

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

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

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 64 FR 7463, Feb. 12, 1999; 72 FR 27442, May 16, 2007]

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§60.5 and 60.6 is governed by §§2.201 through 2.213 of this chapter and not by §2.301 of this chapter.)

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by §60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

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

(e)

(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in §60.8 unless one of the following conditions apply. If no performance test under §60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under §60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in §60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent

possible) under the same operating conditions that existed during the initial performance test conducted under §60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determing compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under §60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in §60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by §60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and §60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under §60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under §60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under §60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under §60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under §60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in §60.13(c) of this part, that the

COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by §60.8, the opacity observation results and observer certification required by §60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by §60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with §60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987; 62 FR 8328, Feb. 24, 1997; 65 FR 61749, Oct. 17, 2000]

§ 60.12 Circumvention.

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

[39 FR 9314, Mar. 8, 1974]

§ 60.13 Monitoring requirements.

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

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under §60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under §60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under §60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under §60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part, The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under §60.8 and as described in §60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under §60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)

(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part, must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of PS–1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry

including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

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

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

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

(h)

(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in §60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.* , one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (*e.g.* hours with < 30 minutes of unit operation under §60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (*e.g.* , ppm pollutant and percent O_2or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the

requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in §60.8 of this subpart or other tests performed following the criteria in §60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §60.45(g) (2) and (3), §60.73(e), and §60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975; 40 FR 59205, Dec. 22, 1975, as amended at 41 FR 35185, Aug. 20, 1976; 48 FR 13326, Mar. 30, 1983; 48 FR 23610, May 25, 1983; 48 FR 32986, July 20, 1983; 52 FR 9782, Mar. 26, 1987; 52 FR 17555, May 11, 1987; 52 FR 21007, June 4, 1987; 64 FR 7463, Feb. 12, 1999; 65 FR 48920, Aug. 10, 2000; 65 FR 61749, Oct. 17, 2000; 66 FR 44980, Aug. 27, 2001; 71 FR 31102, June 1, 2006; 72 FR 32714, June 13, 2007]

Editorial Note: At 65 FR 61749, Oct. 17, 2000, §60.13 was amended by revising the words "ng/J of pollutant" to read "ng of pollutant per J of heat input" in the sixth sentence of paragraph (h). However, the amendment could not be incorporated because the words "ng/J of pollutant" do not exist in the sixth sentence of paragraph (h).

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP–42, or other emission factors determined by the Administrator to be superior to AP–42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and §60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j)

(1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project,* for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

[40 FR 58419, Dec. 16, 1975, as amended at 43 FR 34347, Aug. 3, 1978; 45 FR 5617, Jan. 23, 1980; 57 FR 32339, July 21, 1992; 65 FR 61750, Oct. 17, 2000]

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 FR 58420, Dec. 16, 1975]

§ 60.16 Priority list.

A list of prioritized major source categories may be found at the following EPA web site: ***http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div6&view=text&node=40:6.0.1.1.1.1&idno=40***

§ 60.17 Incorporations by reference.

The materials listed below are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register on the date listed. These materials are incorporated as they exist on the date of the approval, and a notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted below, and all are available for inspection at the Library (C267–01), U.S. EPA, Research Triangle Park, NC or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99–76, 82 (Reapproved 1987), Standard Specification for Ferromanganese, incorporation by reference (IBR) approved for §60.261.

(2) ASTM A100–69, 74, 93, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(3) ASTM A101–73, 93, Standard Specification for Ferrochromium, IBR approved for §60.261.

(4) ASTM A482–76, 93, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.

(5) ASTM A483–64, 74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for §60.261.

(6) ASTM A495–76, 94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§60.562–2(d), 60.593(d), 60.593a(d), and 60.633(h).

(8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, 12.5.2.2.3.

(9) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.4415(a)(1)(i).

(10) ASTM D240–76, 92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and Appendix A: Method 19, Section 12.5.2.2.3.

(11) ASTM D270–65, 75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(12) ASTM D323–82, 94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).

(13) ASTM D388–77, 90, 91, 95, 98a, 99 (Reapproved 2004)ε^1, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.24(h)(8), 60.41 of subpart D of this part, 60.45(f)(4)(i), 60.45(f)(4)(ii), 60.45(f)(4)(vi), 60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4102.

(14) ASTM D388–77, 90, 91, 95, 98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.251(b) and (c) of subpart Y of this part.

(15) ASTM D396–78, 89, 90, 92, 96, 98, Standard Specification for Fuel Oils, IBR approved for §§60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, 60.111(b) of subpart K of this part, and 60.111a(b) of subpart Ka of this part.

(16) ASTM D975–78, 96, 98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) of subpart K of this part and 60.111a(b) of subpart Ka of this part.

(17) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b)(10)(ii).

(18) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.4415(a)(1)(ii).

(19) ASTM D1137–53, 75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f)(5)(i).

(20) ASTM D1193–77, 91, Standard Specification for Reagent Water, IBR approved for Appendix A: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(21) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j)(2) and 60.335(b)(10)(i).

(22) ASTM D1266–98 (Reapproved 2003)e1, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §60.4415(a)(1)(i).

(23) ASTM D1475–60 (Reapproved 1980), 90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d)(1), Appendix A: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(24) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, Section 12.5.2.2.3.

(25) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §60.4415(a)(1)(i).

(26) ASTM D1826–77, 94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f)(5)(ii), 60.46(c)(2), 60.296(b)(3), and Appendix A: Method 19, Section 12.3.2.4.

(27) ASTM D1835–87, 91, 97, 03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, and 60.41c of subpart Dc of this part.

(28) ASTM D1945–64, 76, 91, 96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f)(5)(i).

(29) ASTM D1946–77, 90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f)(3), 60.45(f)(5)(i), 60.564(f)(1), 60.614(e)(2)(ii), 60.614(e)(4), 60.664(e)(2)(ii), 60.664(e)(4), 60.704(d)(2)(ii), and 60.704(d)(4).

(30) ASTM D2013–72, 86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(31) ASTM D2015–77 (Reapproved 1978), 96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(32) ASTM D2016–74, 83, Standard Test Methods for Moisture Content of Wood, IBR approved for Appendix A: Method 28, Section 16.1.1.

(33) ASTM D2234–76, 96, 97b, 98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for Appendix A: Method 19, Section 12.5.2.1.1.

(34) ASTM D2369–81, 87, 90, 92, 93, 95, Standard Test Method for Volatile Content of Coatings, IBR approved for Appendix A: Method 24, Section 6.2.

(35) ASTM D2382–76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).

(36) ASTM D2504–67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g)(5) and 60.485a(g)(5).

(37) ASTM D2584–68 (Reapproved 1985), 94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c)(3)(i).

(38) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for §60.335(b)(9)(i).

(39) ASTM D2622–87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j)(2) and 60.335(b)(10)(i).

(40) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a)(1)(i).

(41) ASTM D2879–83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), 60.485(e)(1), and 60.485a(e)(1).

(42) ASTM D2880–78, 96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).

(43) ASTM D2908–74, 91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).

(44) ASTM D2986–71, 78, 95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for Appendix A: Method 5, Section 7.1.1; Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(45) ASTM D3173–73, 87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(46) ASTM D3176–74, 89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and Appendix A: Method 19, Section 12.3.2.3.

(47) ASTM D3177–75, 89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(48) ASTM D3178–73 (Reapproved 1979), 89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f)(5)(i).

(49) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b)(10)(ii).

(50) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.4415(a)(1)(ii).

(51) ASTM D3270–73T, 80, 91, 95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for Appendix A: Method 13A, Section 16.1.

(52) ASTM D3286–85, 96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(53) ASTM D3370–76, 95a, Standard Practices for Sampling Water, IBR approved for §60.564(j).

(54) ASTM D3792–79, 91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.3.

(55) ASTM D4017–81, 90, 96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for Appendix A: Method 24, Section 6.4.

(56) ASTM D4057–81, 95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.3.

(57) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a)(1).

(58) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h)(1).

(59) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§60.4360 and 60.4415(a)(1)(ii).

(60) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(61) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a)(1).

(62) ASTM D4239–85, 94, 97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(63) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.335(b)(10)(i).

(64) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a)(1)(i).

(65) ASTM D4442–84, 92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for Appendix A: Method 28, Section 16.1.1.

(66) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for Appendix A: Method 28, Section 16.1.1.

(67) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1, 1, 1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.5.

(68) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§60.335(b)(10)(ii) and 60.4415(a)(1)(ii).

(69) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§60.49b(e) and 60.335(b)(9)(i).

(70) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).

(71) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§60.4360 and 60.4415(a)(1)(ii).

(72) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for §60.4415(a)(1).

(73) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for Appendix A: Method 24, Section 6.6.

(74) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.335(b)(10)(i).

(75) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.4415(a)(1)(i).

(76) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§60.334(h)(1) and 60.4360.

(77) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for §60.335(b)(9)(i).

(78) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(79) ASTM D6216–98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for Appendix B, Performance Specification 1.

(80) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §60.334(h)(1).

(81) ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§60.4360 and 60.4415.

(82) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for table 7 of Subpart IIII of this part and table 2 of subpart JJJJ of this part.

(83) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for §60.335(b)(9)(i).

(84) ASTM D6420–99 (Reapproved 2004) Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, IBR approved for table 2 of subpart JJJJ of this part.

(85) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for §60.335(a).

(86) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for table 2 of subpart JJJJ of this part.

(87) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.335(b)(10)(ii).

(88) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.4415(a)(1)(ii).

(89) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Appendix B to part 60, Performance Specification 12A, Section 8.6.2.

(90) ASTM E168–67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(91) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(92) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(b) The following material is available for purchase from the Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12, IBR approved January 27, 1983 for §§60.204(b)(3), 60.214(b)(3), 60.224(b)(3), 60.234(b)(3).

(c) The following material is available for purchase from the American Petroleum Institute, 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved January 27, 1983, for §§60.111(i), 60.111a(f), 60.111a(f)(1) and 60.116b(e)(2)(i).

(d) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), Dunwoody Park, Atlanta, GA 30341.

(1) TAPPI Method T624 os–68, IBR approved January 27, 1983 for §60.285(d)(3).

(e) The following material is available for purchase from the Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103–105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved February 25, 1985 for §60.683(b).

(f) The following material is available for purchase from the following address: Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance.

(g) The following material is available for purchase from the following address: West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5–21 and 90 and 91, September 3, 1970, revised 1984.

(h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

(1) ASME QRO–1–1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§60.56a, 60.54b(a), 60.54b(b), 60.1185(a), 60.1185(c)(2), 60.1675(a), and 60.1675(c)(2).

(2) ASME PTC 4.1–1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§60.46b of subpart Db of this part, 60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)(3) and 60.1810(a)(3).

(3) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)4), and 60.1810(a)(4).

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, Table 2 of subpart JJJJ, and §§60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.

(i) Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846 Third Edition (November 1986), as amended by Updates I (July 1992), II (September 1994), IIA (August, 1993), IIB (January 1995), and III (December 1996). This document may be obtained from the U.S. EPA, Office of Solid Waste and Emergency Response, Waste Characterization Branch, Washington, DC 20460, and is incorporated by reference for appendix A to part 60, Method 29, Sections 7.5.34; 9.2.1; 9.2.3; 10.2; 10.3; 11.1.1; 11.1.3; 13.2.1; 13.2.2; 13.3.1; and Table 29–3.

(j) "Standard Methods for the Examination of Water and Wastewater," 16th edition, 1985. Method 303F: "Determination of Mercury by the Cold Vapor Technique." This document may be obtained from the American Public Health Association, 1015 18th Street, NW., Washington, DC 20036, and is incorporated by reference for appendix A to part 60, Method 29, Sections 9.2.3; 10.3; and 11.1.3.

(k) This material is available for purchase from the American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675–2683. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A–91–61, Item IV–J–124), Room M–1500, 1200 Pennsylvania Ave., NW., Washington, DC.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0–87258–673–5. IBR approved for §60.35e and §60.55c.

(l) This material is available for purchase from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at EPA's Air and Radiation Docket and

Information Center (Docket A–91–61, Item IV–J–125), Room M–1500, 1200 Pennsylvania Ave., NW., Washington, DC.

(1) OMB Bulletin No. 93–17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93–192–664. IBR approved for §60.31e.

(m) This material is available for purchase from at least one of the following addresses: The Gas Processors Association, 6526 East 60th Street, Tulsa, OK, 74145; or Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150–1154. You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460.

(1) Gas Processors Association Method 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for §§60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

(2) [Reserved]

(n) This material is available for purchase from IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) International Organization for Standards 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—Part 4: Test Cycles for Different Engine Applications, IBR approved for §60.4241(b).

(2) [Reserved]

[48 FR 3735, Jan. 27, 1983]

Editorial Note: For Federal Register citations affecting §60.17, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

§ 60.18 General control device requirements.

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)

(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)

(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

$$V_{max}=(X_{H2}-K_1)* K_2$$

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946–77. (Incorporated by reference as specified in §60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)

(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)

(1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

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where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of off gas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{ppm}\right) \left(\frac{g\ mole}{scm}\right) \left(\frac{MJ}{kcal}\right)$$

where the standard temperature for $\left(\frac{g\ mole}{scm}\right)$ is 20°C;

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C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946–77 or 90 (Reapproved 1994) (Incorporated by reference as specified in §60.17); and

H_i = Net heat of combustion of sample component i, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382–76 or 88 or D4809–95 (incorporated by reference as specified in §60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10}(V_{max})=(H_T+28.8)/31.7$$

V_{max} = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$$V_{max} = 8.706+0.7084\ (H_T)$$

V_{max} = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

[51 FR 2701, Jan. 21, 1986, as amended at 63 FR 24444, May 4, 1998; 65 FR 61752, Oct. 17, 2000]

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)

(1)

(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator,

such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[59 FR 12428, Mar. 16, 1994, as amended at 64 FR 7463, Feb. 12, 1998]

STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978

(version dated 10/16/2007)

E.U. ID No.	Brief Description
-016 & -017	SJRPP Boiler Nos. 1 & 2
-026 & -027	NGS Circulating Fluidized Bed Boiler Nos. 2 & 1

Federal Regulations Adopted by Reference

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

Federal Revision Date: June 13, 2007

State Rule Effective Date: October 1, 2007

Standardized Conditions Revision Date: October 16, 2007

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

Source: 72 FR 32722, June 13, 2007, unless otherwise noted.

Index

End of Index

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) Combined cycle gas turbines (both the stationary combustion turbine and any associated duct burners) are subject to this part and not subject to subpart GG or KKKK of this part if:

(1) The combined cycle gas turbine is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis; and

(3) The combined cycle gas turbine commenced construction, modification, or reconstruction after February 28, 2005.

(4) This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the stationary combustion turbine is subject to either subpart GG or KKKK of this part, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41Da Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Biomass means plant materials and animal waste.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides (SO_2) from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (*e.g.* , a holding company with operating subsidiary companies).

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or *ESP* means an add-on air pollution control device used to capture particulate matter (PM) by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emergency condition means that period of time when:

(1) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(i) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(ii) All available purchase power interconnected with the affected facility is being obtained, or

(2) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(3) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under paragraph (1) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the fuel burned in stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per standard cubic meter (910 and 1,150 Btu per standard cubic foot).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(1) For particulate matter (PM) is:

(i) 3,000 ng/J (7.0 lb/MMBtu) heat input for solid fuel; and

(ii) 73 ng/J (0.17 lb/MMBtu) heat input for liquid fuels.

(2) For sulfur dioxide (SO_2) is determined under §60.50Da(c).

(3) For nitrogen oxides (NO_X) is:

(i) 290 ng/J (0.67 lb/MMBtu) heat input for gaseous fuels;

(ii) 310 ng/J (0.72 lb/MMBtu) heat input for liquid fuels; and

(iii) 990 ng/J (2.30 lb/MMBtu) heat input for solid fuels.

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.* , a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Spare flue gas desulfurization system module means a separate system of SO_2 emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (*e.g.* , emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

Wet flue gas desulfurization technology or *wet FGD* means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

§ 60.42Da Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) Except as provided in paragraph (d) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

§ 60.43Da Standard for sulfur dioxide (SO_2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO_2 in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO_2 in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of SO_2 to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of SO_2 to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

E_s = Prorated SO_2 emission limit (ng/J heat input);

$\%P_s$ = Percentage of potential SO_2 emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

§ 60.44Da Standard for nitrogen oxides (NO_X).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average basis, except as provided under §60.48Da(j)(1):

(1) NO_X emission limits.

Fuel type	**Emission limit for heat input**	
	ng/J	**lb/MMBtu**
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50

All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1]Exempt from NO_X standards and NO_X monitoring requirements.

[2]Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NO_X reduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraphs (d), (e), and (f) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

E_n= Applicable standard for NO_X when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)

(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average basis.

(e) Except for an IGCC electric utility steam generating unit meeting the requirements of paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

§ 60.45Da Standard for mercury (Hg).

(a) For each coal-fired electric utility steam generating unit other than an IGCC electric utility steam generating unit, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average basis using the procedures in §60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 20×10^{-6} pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 ng/J.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 97×10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 175×10^{-6} lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 16×10^{-6} lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.* , bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

EL_i = Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

HH_i = For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emission limit based on the Btu, MWh, or MJ contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source. You must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit contributed by both regulated and nonregulated fuels burned during the compliance period and the total Btu, MWh, or MJ contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average basis using the procedures in §60.50Da(h).

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_X emission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SCR I)	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquification	NO_X	750–10,000
Total allowable for all technologies		15,000

§ 60.48Da Compliance provisions.

(a) Compliance with the PM emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for PM under §60.42Da(a)(2) and (3).

(b) Compliance with the NO_X emission limitation under §60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The PM emission standards under §60.42Da, the NO_X emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if SO_2 emissions are minimized by:

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

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any SO_2 emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 MMBtu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph under §60.43Da(a), (b), (d), (e), and (h) for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under §60.8, compliance with the SO_2 emission limitations and percentage reduction requirements under §60.43Da and the NO_X emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both SO_2 and NO_X and a new percent reduction for SO_2 are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limitations and percent reduction requirements under §60.43Da and the NO_X emission limitation under §60.44Da is based on the average emission rates for SO_2, NO_X, and percent reduction for SO_2 for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2 only).

(2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, the valid hourly emission rates are averaged with the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f)* . The owner or operator of an affected facility subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f) shall calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, NO_X emissions may be calculated by multiplying the hourly NO_X emission rate in lb/MMBtu (measured by the CEMS required under §§60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1)* . To determine compliance with the emissions limits for NO_X required by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system (CEMS) specified under §60.49Da for measuring NO_X and oxygen (O_2) (or carbon dioxide (CO_2)) and meet the requirements of §60.49Da. Alternatively, data from a NO_X emission rate (*i.e.* , NO_X-diluent) CEMS certified according to the provisions of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats.

Data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emission rate at the outlet from the steam generating unit shall constitute the NO_X emission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1)*. To determine compliance with the emission limitation for NO_X required by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_X shall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \quad \text{(Eq. 2)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

C_{te} = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O_{sg} = Average hourly gross energy output from steam generating unit, J (MWh); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sd})}{O_{cc}} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J (MWh).

(ii) The CEMS specified under §60.49Da for measuring NO_X and O_2(or CO_2) shall be used to determine the average hourly NO_X concentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NO_X emissions by installing, operating, and maintaining continuous fuel flow meters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \qquad \text{(Eq. 4)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;

ER_{sg} = Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc} = Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J (MWh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) *Compliance provisions for sources subject to §60.45Da.* The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i).* The owner or operator of an affected facility subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i) shall calculate SO_2 emissions as 1.660×10^{-7}lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(n) *Compliance provisions for sources subject to §60.42Da(c)(1).* The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section and use a COMS to demonstrate compliance with §60.42Da(b).

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in 60.42Da(c)(2) or (d) by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months of the date of the prior performance test. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your calculated average opacity value for all of the test runs is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected source remains at a level greater than the opacity baseline level after 7 days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a wavier is granted by the appropriate delegated permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the daily average liquid-to-gas flow rate for the wet scrubber must be maintained at 90 percent of average ratio measured during all test run intervals for the performance test conducted according to paragraph (o)(1) of this section.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the appropriate delegated permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS "Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring .

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the model parameter was first determined to exceed its baseline level unless a wavier is granted by the appropriate delegated permitting authority.

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

(A) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (*e.g.* , using a strip chart recorder or a data logger.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the appropriate delegated permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

(H) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ii) You must develop and submit to the appropriate delegated permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

(B) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(C) Operation of the bag leak detection system, including quality assurance procedures;

(D) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(E) How the bag leak detection system output will be recorded and stored; and

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the appropriate delegated permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(A) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(B) Sealing off defective bags or filter media;

(C) Replacing defective bags or filter media or otherwise repairing the control device;

(D) Sealing off a defective fabric filter compartment;

(E) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) Of after any period of composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the alarm rate was first determined to exceed 5 percent limit unless a wavier is granted by the appropriate delegated permitting authority.

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis. Beginning on January 1, 2012, valid CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average basis.

   (i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

   (ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-day rolling average.

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) SO_2 emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO_2 continuous emissions monitoring system (CEMS) according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO_2 or O_2 continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO_2 concentration data and CO_2(or O_2) data are collected simultaneously; and

(B) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_X emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or carbon dioxide (CO_2) content of the flue gases at each location where SO_2 or NO_X emissions are monitored. For affected facilities subject to a lb/MMBtu SO_2emission limit under §60.43Da, if the owner or operator has installed and certified a CO_2 or O_2 monitoring system according to §75.20(c) of this chapter and Appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2 concentration monitoring system described in paragraph (b) of this section, to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)

(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

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

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

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

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O_2, SO_2, and NO_X concentrations, respectively.

(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a CEMS for measuring opacity is between 60 and 80 percent. Span values for a CEMS measuring NO_X shall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, NO_X span values shall be determined as follows:

Fossil fuel	Span values for NO_X (ppm)
Gas	500.
Liquid	500.
Solid	1,000.
Combination	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel,

y = Fraction of total heat input derived from liquid fossil fuel, and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2 control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2 span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO_X standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.* , on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1), (2) or (3) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A CEMS for measuring PM emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section; or

(2) The affected source burns only gaseous fuels and does not use a post-combustion technology to reduce emissions of SO_2 or PM; or

(3) The affected source does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (u)(3)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(3)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using the following test methods.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O_2 (or CO_2), EPA Reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(w)

(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, the SO_2, NO_X, CO_2, and O_2 CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with

Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da., the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required CO_2 and O_2 CEMS and for SO_2 and NO_X CEMS with span values greater than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO_2 and NO_X span values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required CO_2 and O_2 CEMS and for SO_2 and NO_X CEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_X span values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2 CEMS and for NO_X CEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of

the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO_2 and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in §60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(2) For the particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2 standards in §60.43Da as follows:

(1) The percent of potential SO_2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:

%Ps = Percent of potential SO_2 emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO_2 control system, percent.

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

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2 reduction ($\%R_g$) of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A

of this part, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

(d) The owner or operator shall determine compliance with the NO_X standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO_X.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of NO_X and CO_2 or O_2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for PM, SO_2, and NO_X using the procedures of Method 19 of appendix A of this part. The SO_2 and NO_X emission rates from the gas turbine used in Method 19 of appendix A of this part calculations are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

(g) For the purposes of determining compliance with the emission limits in §60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus 75 percent of the equivalent electrical energy (measured relative to ISO conditions) in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.* , 250 MMBtu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 MMBtu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 5 in this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \qquad \text{(Eq. 5)}$$

Where:

ER_{cogen} = Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

V_{grid} = Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$ = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required CEMS must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the CEMS for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in lb, using either Equation 6 in paragraph (h)(2)(i)(A) of this section or Equation 7 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 8 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 6 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h \qquad \text{(Eq. 6)}$$

Where:

E_h = Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11} lb-scm/µgm-scf;

C_h = Hourly H_g concentration, wet basis, (µgm/scm);

Q_h = Hourly stack gas volumetric flow rate, (scfh); and

t_h = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 7 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h \, Q_h \, t_h \, (1 - B_{ws}) \qquad \text{(Eq. 7)}$$

Where:

E_h = Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11} lb-scm/µgm-scf;

C_h = Hourly Hg concentration, dry basis, (µgm/dscm);

Q_h = Hourly stack gas volumetric flow rate, (scfh);

t_h = Unit operating time, *i.e.* , the fraction of the hour for which the unit operated; and

B_{ws} = Stack gas moisture content, expressed as a decimal fraction (*e.g.* , for 8 percent H_2O, B_{ws}= 0.08).

(C) Use Equation 8, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 6 or 7 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 8)}$$

Where:

M = Total Hg mass emissions for the month, (lb);

E_h = Hg mass emissions for hour "h", from Equation 6 or 7 of this section, (lb); and

n = Number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 9)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12} (ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \qquad \text{(Eq. 10)}$$

Where:

E_{avg} = Weighted 12-month rolling average Hg emission rate, (lb/MWh);

ER_i = Monthly Hg emission rate, for month "i", (lb/MWh); and

n = Number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 7 through 9 of this section, except that for a particular pair of sorbent traps, C_h in Equation 7 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For SO_2 and NO_X the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average SO_2 and NO_X emission rates (ng/J or lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_X only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

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

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

(iv) Percent reduction in emissions achieved;

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

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the SO_2 emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

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

(f) For any periods for which opacity, SO_2 or NO_X emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

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

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

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

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

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

STANDARDS OF PERFORMANCE FOR COAL PREPARATION PLANTS

(version dated 4/18/2008)

E.U. ID No.	Brief Description
-023	SJRPP: Fuel and Limestone Handling and Storage Operations
-029	NGS: Crusher House Building Baghouse Exhaust
-031	NGS: Fuel Silos Dust Collectors

Federal Regulations Adopted by Reference

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

Federal Revision Date: October 17; 2000

Rule Effective Date: June 21, 2002

Standardized Conditions Revision Date: April 18, 2008

40 CFR Part 60, Subpart Y - Standards of Performance for Coal Preparation Plants

Index

End of Index

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.

[42 FR 37938, July 25, 1977; 42 FR 44812, Sept. 7, 1977, as amended at 65 FR 61757, Oct. 17, 2000]

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Act and in subpart A of this part.

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(c) *Coal* means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(d) *Cyclonic flow* means a spiraling movement of exhaust gases within a duct or stack.

(e) *Thermal dryer* means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) *Pneumatic coal-cleaning equipment* means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

[41 FR 2234, Jan. 15, 1976, as amended at 48 FR 3738, Jan. 27, 1983; 65 FR 61757, Oct. 17, 2000]

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.017 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

[41 FR 2234, Jan. 15, 1976, as amended at 65 FR 61757, Oct. 17, 2000]

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under §60.13(b).

[41 FR 2234, Jan. 15, 1976, as amended at 54 FR 6671, Feb. 14, 1989; 65 FR 61757, Oct. 17, 2000]

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in §60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

[54 FR 6671, Feb. 14, 1989]

STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS
(version dated 7/1/2008)

E.U. ID No.	Brief Description
-033	NGS: Limestone Dryers/Mills Building
-034	NGS: Limestone Prep Building Dust Collectors
-035	NGS: Limestone Silos Bin Vent Filters

Federal Regulations Adopted by Reference

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

Federal Revision Date: October 17, 2000

Rule Effective Date: June 21, 2002

Standardized Conditions Revision Date: July 1, 2008

40 CFR Part 60, Subpart OOO - Standards of Performance for Nonmetallic Mineral Processing Plants

Source: 51 FR 31337, Aug. 1, 1985, unless otherwise noted.

Index

End of Index

§ 60.670 Applicability and designation of affected facility.

(a)

(1) Except as provided in paragraphs (a)(2), (b), (c), and (d) of this section, the provisions of this subpart are applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin are subject to the provisions of this subpart.

(2) The provisions of this subpart do not apply to the following operations: All facilities located in underground mines; and stand-alone screening operations at plants without crushers or grinding mills.

(b) An affected facility that is subject to the provisions of subpart F or I or that follows in the plant process any facility subject to the provisions of subparts F or I of this part is not subject to the provisions of this subpart.

(c) Facilities at the following plants are not subject to the provisions of this subpart:

(1) Fixed sand and gravel plants and crushed stone plants with capacities, as defined in §60.671, of 23 megagrams per hour (25 tons per hour) or less;

(2) Portable sand and gravel plants and crushed stone plants with capacities, as defined in §60.671, of 136 megagrams per hour (150 tons per hour) or less; and

(3) Common clay plants and pumice plants with capacities, as defined in §60.671, of 9 megagrams per hour (10 tons per hour) or less.

(d)

(1) When an existing facility is replaced by a piece of equipment of equal or smaller size, as defined in §60.671, having the same function as the existing facility, the new facility is exempt from the provisions of §§60.672, 60.674, and 60.675 except as provided for in paragraph (d)(3) of this section.

(2) An owner or operator complying with paragraph (d)(1) of this section shall submit the information required in §60.676(a).

(3) An owner or operator replacing all existing facilities in a production line with new facilities does not qualify for the exemption described in paragraph (d)(1) of this section and must comply with the provisions of §§60.672, 60.674 and 60.675.

(e) An affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after August 31, 1983 is subject to the requirements of this part.

(f) Table 1 of this subpart specifies the provisions of subpart A of this part 60 that apply and those that do not apply to owners and operators of affected facilities subject to this subpart.

STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS
(version dated 7/1/2008)

Table 1—Applicability of Subpart A to Subpart OOO

Subpart A reference	Applies to Subpart OOO	Comment
60.1, Applicability	Yes	
60.2, Definitions	Yes	
60.3, Units and abbreviations	Yes	
60.4, Address:		
(a)	Yes	
(b)	Yes	
60.5, Determination of construction or modification	Yes	
60.6, Review of plans	Yes	
60.7, Notification and recordkeeping	Yes	Except in (a)(2) report of anticipated date of initial startup is not required (§60.676(h)).
60.8, Performance tests	Yes	Except in (d), after 30 days notice for an initially scheduled performance test, any rescheduled performance test requires 7 days notice, not 30 days (§60.675(g)).
60.9, Availability of information	Yes	
60.10, State authority	Yes	
60.11, Compliance with standards and maintenance requirements	Yes	Except in (b) under certain conditions (§§60.675 (c)(3) and (c)(4)), Method 9 observation may be reduced from 3 hours to 1 hour. Some affected facilities exempted from Method 9 tests (§60.675(h)).
60.12, Circumvention	Yes	
60.13, Monitoring requirements	Yes	
60.14, Modification	Yes	

60.15, Reconstruction	Yes	
60.16, Priority list	Yes	
60.17, Incorporations by reference	Yes	
60.18, General control device	No	Flares will not be used to comply with the emission limits.
60.19, General notification and reporting requirements	Yes	

[51 FR 31337, Aug. 1, 1985, as amended at 62 FR 31359, June 9, 1997]

§ 60.671 Definitions.

All terms used in this subpart, but not specifically defined in this section, shall have the meaning given them in the Act and in subpart A of this part.

Bagging operation means the mechanical process by which bags are filled with nonmetallic minerals.

Belt conveyor means a conveying device that transports material from one location to another by means of an endless belt that is carried on a series of idlers and routed around a pulley at each end.

Bucket elevator means a conveying device of nonmetallic minerals consisting of a head and foot assembly which supports and drives an endless single or double strand chain or belt to which buckets are attached.

Building means any frame structure with a roof.

Capacity means the cumulative rated capacity of all initial crushers that are part of the plant.

Capture system means the equipment (including enclosures, hoods, ducts, fans, dampers, etc.) used to capture and transport particulate matter generated by one or more process operations to a control device.

Control device means the air pollution control equipment used to reduce particulate matter emissions released to the atmosphere from one or more process operations at a nonmetallic mineral processing plant.

Conveying system means a device for transporting materials from one piece of equipment or location to another location within a plant. Conveying systems include but are not limited to the following: Feeders, belt conveyors, bucket elevators and pneumatic systems.

Crusher means a machine used to crush any nonmetallic minerals, and includes, but is not limited to, the following types: jaw, gyratory, cone, roll, rod mill, hammermill, and impactor.

Enclosed truck or railcar loading station means that portion of a nonmetallic mineral processing plant where nonmetallic minerals are loaded by an enclosed conveying system into enclosed trucks or railcars.

Fixed plant means any nonmetallic mineral processing plant at which the processing equipment specified in §60.670(a) is attached by a cable, chain, turnbuckle, bolt or other means (except electrical connections) to any anchor, slab, or structure including bedrock.

Fugitive emission means particulate matter that is not collected by a capture system and is released to the atmosphere at the point of generation.

Grinding mill means a machine used for the wet or dry fine crushing of any nonmetallic mineral. Grinding mills include, but are not limited to, the following types: hammer, roller, rod, pebble and ball, and fluid energy. The grinding mill includes the air conveying system, air separator, or air classifier, where such systems are used.

Initial crusher means any crusher into which nonmetallic minerals can be fed without prior crushing in the plant.

Nonmetallic mineral means any of the following minerals or any mixture of which the majority is any of the following minerals:

(a) Crushed and Broken Stone, including Limestone, Dolomite, Granite, Traprock, Sandstone, Quartz, Quartzite, Marl, Marble, Slate, Shale, Oil Shale, and Shell.

(b) Sand and Gravel.

(c) Clay including Kaolin, Fireclay, Bentonite, Fuller's Earth, Ball Clay, and Common Clay.

(d) Rock Salt.

(e) Gypsum.

(f) Sodium Compounds, including Sodium Carbonate, Sodium Chloride, and Sodium Sulfate.

(g) Pumice.

(h) Gilsonite.

(i) Talc and Pyrophyllite.

(j) Boron, including Borax, Kernite, and Colemanite.

(k) Barite.

(l) Fluorospar.

(m) Feldspar.

(n) Diatomite.

(o) Perlite.

(p) Vermiculite.

(q) Mica.

(r) Kyanite, including Andalusite, Sillimanite, Topaz, and Dumortierite.

Nonmetallic mineral processing plant means any combination of equipment that is used to crush or grind any nonmetallic mineral wherever located, including lime plants, power plants, steel mills, asphalt concrete plants, portland cement plants, or any other facility processing nonmetallic minerals except as provided in §60.670 (b) and (c).

Portable plant means any nonmetallic mineral processing plant that is mounted on any chassis or skids and may be moved by the application of a lifting or pulling force. In addition, there shall be no cable, chain, turnbuckle, bolt or other means (except electrical connections) by which any piece of equipment is attached or clamped to any anchor, slab, or structure, including bedrock that must be removed prior to the application of a lifting or pulling force for the purpose of transporting the unit.

Production line means all affected facilities (crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck and railcar loading stations) which are directly connected or are connected together by a conveying system.

Screening operation means a device for separating material according to size by passing undersize material through one or more mesh surfaces (screens) in series, and retaining oversize material on the mesh surfaces (screens).

Size means the rated capacity in tons per hour of a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station; the total surface area of the top screen of a screening operation; the width of a conveyor belt; and the rated capacity in tons of a storage bin.

Stack emission means the particulate matter that is released to the atmosphere from a capture system.

Storage bin means a facility for storage (including surge bins) or nonmetallic minerals prior to further processing or loading.

Transfer point means a point in a conveying operation where the nonmetallic mineral is transferred to or from a belt conveyor except where the nonmetallic mineral is being transferred to a stockpile.

Truck dumping means the unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another. Movable vehicles include but are not limited to: trucks, front end loaders, skip hoists, and railcars.

Vent means an opening through which there is mechanically induced air flow for the purpose of exhausting from a building air carrying particulate matter emissions from one or more affected facilities.

Wet mining operation means a mining or dredging operation designed and operated to extract any nonmetallic mineral regulated under this subpart from deposits existing at or below the water table, where the nonmetallic mineral is saturated with water.

Wet screening operation means a screening operation at a nonmetallic mineral processing plant which removes unwanted material or which separates marketable fines from the product by a washing process which is designed and operated at all times such that the product is saturated with water.

[51 FR 31337, Aug. 1, 1985, as amended at 62 FR 31359, June 9, 1997]

§ 60.672 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any stack emissions which:

  (1) Contain particulate matter in excess of 0.05 g/dscm (0.022 gr/dscf); and

  (2) Exhibit greater than 7 percent opacity, unless the stack emissions are discharged from an affected facility using a wet scrubbing control device. Facilities using a wet scrubber must comply with the reporting provisions of §60.676 (c), (d), and (e).

(b) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any fugitive emissions which exhibit greater than 10 percent opacity, except as provided in paragraphs (c), (d), and (e) of this section.

(c) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator shall cause to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions which exhibit greater than 15 percent opacity.

(d) Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section.

(e) If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a), (b) and (c) of this section, or the building enclosing the affected facility or facilities must comply with the following emission limits:

(1) No owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other affected facility any visible fugitive emissions except emissions from a vent as defined in §60.671.

(2) No owner or operator shall cause to be discharged into the atmosphere from any vent of any building enclosing any transfer point on a conveyor belt or any other affected facility emissions which exceed the stack emissions limits in paragraph (a) of this section.

(f) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator shall cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual, enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity.

(g) Owners or operators of multiple storage bins with combined stack emissions shall comply with the emission limits in paragraph (a)(1) and (a)(2) of this section.

(h) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup, no owner or operator shall cause to be discharged into the atmosphere any visible emissions from:

(1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to the next crusher, grinding mill or storage bin.

(2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

[51 FR 31337, Aug. 1, 1985, as amended at 62 FR 31359, June 9, 1997; 65 FR 61778, Oct. 17, 2000]

§ 60.673 Reconstruction.

(a) The cost of replacement of ore-contact surfaces on processing equipment shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital cost that would be required to construct a comparable new facility" under §60.15. Ore-contact surfaces are crushing surfaces; screen meshes, bars, and plates; conveyor belts; and elevator buckets.

(b) Under §60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components (except components specified in paragraph (a) of this section) which are or will be replaced pursuant to all continuous programs of component replacement commenced within any 2-year period following August 31, 1983.

§ 60.674 Monitoring of operations.

The owner or operator of any affected facility subject to the provisions of this subpart which uses a wet scrubber to control emissions shall install, calibrate, maintain and operate the following monitoring devices:

(a) A device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±250 pascals ±1 inch water gauge pressure and must be calibrated on an annual basis in accordance with manufacturer's instructions.

(b) A device for the continuous measurement of the scrubbing liquid flow rate to the wet scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±5 percent of design scrubbing liquid flow rate and must be calibrated on an annual basis in accordance with manufacturer's instructions.

§ 60.675 Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.672(a) as follows:

(1) Method 5 or Method 17 shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5, if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c)

(1) In determining compliance with the particulate matter standards in §60.672 (b) and (c), the owner or operator shall use Method 9 and the procedures in §60.11, with the following additions:

(i) The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet).

(ii) The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources (e.g., road dust). The required observer position relative to the sun (Method 9, Section 2.1) must be followed.

(iii) For affected facilities using wet dust suppression for particulate matter control, a visible mist is sometimes generated by the spray. The water mist must not be confused with particulate matter emissions and is not to be considered a visible emission. When a water mist of this nature is present, the observation of emissions is to be made at a point in the plume where the mist is no longer visible.

(2) In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under §60.672(f) of this subpart, using Method 9, the duration of the Method 9 observations shall be 1 hour (ten 6-minute averages).

(3) When determining compliance with the fugitive emissions standard for any affected facility described under §60.672(b) of this subpart, the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply:

(i) There are no individual readings greater than 10 percent opacity; and

(ii) There are no more than 3 readings of 10 percent for the 1-hour period.

(4) When determining compliance with the fugitive emissions standard for any crusher at which a capture system is not used as described under §60.672(c) of this subpart, the duration of the Method 9

observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply:

(i) There are no individual readings greater than 15 percent opacity; and

(ii) There are no more than 3 readings of 15 percent for the 1-hour period.

(d) In determining compliance with §60.672(e), the owner or operator shall use Method 22 to determine fugitive emissions. The performance test shall be conducted while all affected facilities inside the building are operating. The performance test for each building shall be at least 75 minutes in duration, with each side of the building and the roof being observed for at least 15 minutes.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For the method and procedure of paragraph (c) of this section, if emissions from two or more facilities continuously interfere so that the opacity of fugitive emissions from an individual affected facility cannot be read, either of the following procedures may be used:

(i) Use for the combined emission stream the highest fugitive opacity standard applicable to any of the individual affected facilities contributing to the emissions stream.

(ii) Separate the emissions so that the opacity of emissions from each affected facility can be read.

(f) To comply with §60.676(d), the owner or operator shall record the measurements as required in §60.676(c) using the monitoring devices in §60.674 (a) and (b) during each particulate matter run and shall determine the averages.

(g) If, after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting any rescheduled performance test required in this section, the owner or operator of an affected facility shall submit a notice to the Administrator at least 7 days prior to any rescheduled performance test.

(h) Initial Method 9 performance tests under §60.11 of this part and §60.675 of this subpart are not required for:

(1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to, but not including the next crusher, grinding mill or storage bin.

(2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, that process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

[54 FR 6680, Feb. 14, 1989, as amended at 62 FR 31360, June 9, 1997]

§ 60.676 Reporting and recordkeeping.

(a) Each owner or operator seeking to comply with §60.670(d) shall submit to the Administrator the following information about the existing facility being replaced and the replacement piece of equipment.

(1) For a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station:

(i) The rated capacity in megagrams or tons per hour of the existing facility being replaced and

(ii) The rated capacity in tons per hour of the replacement equipment.

(2) For a screening operation:

(i) The total surface area of the top screen of the existing screening operation being replaced and

(ii) The total surface area of the top screen of the replacement screening operation.

(3) For a conveyor belt:

(i) The width of the existing belt being replaced and

(ii) The width of the replacement conveyor belt.

(4) For a storage bin:

(i) The rated capacity in megagrams or tons of the existing storage bin being replaced and

(ii) The rated capacity in megagrams or tons of replacement storage bins.

(b) [Reserved]

(c) During the initial performance test of a wet scrubber, and daily thereafter, the owner or operator shall record the measurements of both the change in pressure of the gas stream across the scrubber and the scrubbing liquid flow rate.

(d) After the initial performance test of a wet scrubber, the owner or operator shall submit semiannual reports to the Administrator of occurrences when the measurements of the scrubber pressure loss (or gain) and liquid flow rate differ by more than ±30 percent from the averaged determined during the most recent performance test.

(e) The reports required under paragraph (d) shall be postmarked within 30 days following end of the second and fourth calendar quarters.

(f) The owner or operator of any affected facility shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in §60.672 of this subpart, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b), (c), and (f), and reports of observations using Method 22 to demonstrate compliance with §60.672(e).

(g) The owner or operator of any screening operation, bucket elevator, or belt conveyor that processes saturated material and is subject to §60.672(h) and subsequently processes unsaturated materials, shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the 10 percent opacity limit in §60.672(b) and the emission test requirements of §60.11 and this subpart. Likewise a screening operation, bucket elevator, or belt conveyor that processes unsaturated material but subsequently processes saturated material shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the no visible emission limit in §60.672(h).

(h) The subpart A requirement under §60.7(a)(2) for notification of the anticipated date of initial startup of an affected facility shall be waived for owners or operators of affected facilities regulated under this subpart.

(i) A notification of the actual date of initial startup of each affected facility shall be submitted to the Administrator.

(1) For a combination of affected facilities in a production line that begin actual initial startup on the same day, a single notification of startup may be submitted by the owner or operator to the Administrator. The notification shall be postmarked within 15 days after such date and shall include a description of each affected facility, equipment manufacturer, and serial number of the equipment, if available.

(2) For portable aggregate processing plants, the notification of the actual date of initial startup shall include both the home office and the current address or location of the portable plant.

(j) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected facilities within the State will be relieved of the obligation to comply with the reporting requirements of this section, provided that they comply with requirements established by the State.

[51 FR 31337, Aug. 1, 1985, as amended at 54 FR 6680, Feb. 14, 1989; 62 FR 31360, June 9, 1997; 65 FR 61778, Oct. 17, 2000]

APPENDIX NGS CT HEAT INPUT NORMINAL VALUE

HEAT LOAD MW VS TEMPERATURE

Attachment NGS: CT Heat Input Nominal Values

NORTHSIDE STATION COMBUSTION TURBINES
BASE LOAD MW vs TEMPERATURE

#	AMBIENT TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR	AMBIENT TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR
1	20	67.97	67.63	868	60	58.77	58.43	747
2	21	67.74	67.40	865	61	58.54	58.20	744
3	22	67.51	67.17	861	62	58.31	57.97	741
4	23	67.28	66.94	858	63	58.08	57.74	735
5	24	67.05	66.71	855	64	57.85	57.51	735
6	25	66.82	65.48	852	65	57.62	57.28	733
7	26	66.59	66.25	849	66	57.39	57.05	730
8	27	66.36	66.02	846	67	57.16	56.82	727
9	28	66.13	65.79	842	68	56.93	56.59	724
10	29	65.90	65.56	839	69	56.70	56.36	721
11	30	65.67	65.33	836	70	56.47	56.13	719
12	31	65.44	65.10	833	71	56.24	55.90	716
13	32	65.21	64.87	830	72	56.01	55.67	713
14	33	64.98	64.64	827	73	55.78	55.44	710
15	34	64.75	64.41	824	74	55.55	55.21	708
16	35	64.52	64.18	821	75	55.32	54.98	705
17	36	64.29	63.95	818	76	55.09	54.75	702
18	37	64.06	63.72	815	77	54.86	54.52	699
19	38	63.83	63.49	812	78	54.63	54.29	697
20	39	63.60	63.26	809	79	54.40	54.06	694
21	40	63.37	63.03	806	80	54.17	53.83	691
22	41	63.14	62.80	802	81	53.94	53.60	689
23	42	62.91	62.57	799	82	53.71	53.37	686
24	43	62.68	62.34	796	83	53.48	53.14	683
25	44	62.45	62.11	793	84	53.25	52.91	681
26	45	62.22	61.88	791	85	53.02	52.68	678
27	46	61.99	61.65	788	86	52.79	52.45	675
28	47	61.76	61.42	785	87	52.56	52.22	673
29	48	61.53	61.19	782	88	52.33	51.99	670
30	49	61.30	60.96	779	89	52.10	51.76	667
31	50	61.07	60.73	776	90	51.87	51.53	665
32	51	60.84	60.50	773	91	51.64	51.30	662
33	52	60.61	60.27	770	92	51.41	51.07	660
34	53	60.38	60.04	767	93	51.18	50.84	657
35	54	60.15	59.81	764	94	50.95	50.61	654
36	55	59.92	59.58	761	95	50.72	50.38	652
37	56	59.69	59.35	758	95	50.49	50.15	649
38	57	59.46	59.12	755	97	50.26	49.92	647
39	58	59.23	58.89	753	98	50.03	49.69	644
40	59	59.00	58.66	750	99	49.80	49.46	641
41	60	58.77	58.43	747	100	49.57	49.23	639

KSCT	
Y INTERCEPT	72.576
SLOPE	0.2301

DISPATCH HEAT RATE CURVES

A =	1.79910E+02
B =	8.82453E+00
C =	-1.50785E-02
D =	5.20028E-04
AA =	2.40192E-01
BB =	9.99987E-01
CC =	1.79499E-07
DATE:	05/21/93

Jacksonville Electric Authority

Operation and Maintenance Plan

Operation and Maintenance

Following is a list of activities to be accomplished for the control of particulate emissions from units in or impacting the Duval County maintenance areas. These schedules apply to each on-line unit.

Daily:

1. Check and clean burners (renew tips as necessary) daily.
2. Conduct one complete soot-blowing cycle (or as needed).
3. Maintain optimum fuel oil temperature and pressure at all times.

Weekly:

1. Clean low pressure fuel oil strainers (more frequently if required).
2. Clean other fuel oil strainers as needed by monitoring the pressure drop.

Annually:

1. Clean the boiler and inspect baffles.
2. Inspect the:
   - (a) wind box;
   - (b) registers;
   - (c) diffusers;
   - (d) refractory throat;
   - (e) scanners;
   - (f) ignitors.
3. Adjust the air registers for optimum flame pattern with assistance from Engineering Services.
4. Replace burner tips (more frequently if required).

PROCEDURES FOR STARTUP AND SHUTDOWN

O&M PROCEDURES

Procedures for startup and shutdown will be completed in accordance with the manufactures' operating procedures and/or based on plant experience. Excess emissions resulting from startup and shutdown are permitted in condition 26 of PSD-FL-265 and in the specific permit conditions of the Title V air operation permit with Rule 62-210.700(1) referenced.

The following is further information on startup and shutdown of specific emissions units.

E.U. ID No.	Brief Description
-026	NGS Circulating Fluidized Bed Boiler No. 2
-027	NGS Circulating Fluidized Bed Boiler No. 1

NGS – CFB Nos. 1 and 2

Startup and Shutdown Procedures

The CFBs are started and shut down in the most efficient manner possible taking into account manufacturer recommendations, personnel and equipment safety and limitations, operating experience, and other factors such as fuel type and process variables.

E.U. ID No.	Brief Description
-003	NGS Boiler No. 3

NGS – Boiler No. 3

Startup and Shutdown Plans – O&M Procedures

The JEA will maintain and operate Boiler No. 3 efficiently to maximum performance to minimize environmental emissions. JEA will take necessary actions to ensure the unit does not exceed permitted limits, and will remove a unit from service if required.

NGS Boiler No. 3 is started-up on natural gas. L.P. gas is used as ignitor fuel source. After startup the unit is fueled by natural gas and/or #6 fuel oil, depending upon availability.

All JEA units are operated under the boiler, turbine/generator, and operational guidelines as furnished by the manufacturers and JEA internal guidelines and procedures.

Boiler equipment is maintained under a preventative maintenance (P.M.) routine schedule as set forth in JEA's internal P.M. program. Some examples of boiler equipment P.M.'s are: weekly burner cleaning, daily sootblowing, scheduled boiler washings, and continuous boiler emission monitoring. Other maintenance is performed on an as needed basis. When excessive emission conditions occur, the control room operator takes immediate corrective action.

PROCEDURES FOR STARTUP AND SHUTDOWN
O&M Procedures

When a unit shut down is required or unit trip occurs, the unit is brought down under established manufacturer and JEA operational procedures.

E.U. ID No.	Brief Description
-006	NGS: Combustion Turbine No. 3
-007	NGS: Combustion Turbine No. 4
-008	NGS: Combustion Turbine No. 5
-009	NGS: Combustion Turbine No. 6

NGS – Combustion Turbines No. 3, No. 4, No. 5 and No. 6

O&M Plans – Startup and Shutdown Plans

The JEA will maintain and operate Combustion Turbines (CTs) No. 3, No. 4, No. 5 and No. 6 efficiently to maximum performance to minimize environmental emissions. JEA will take necessary actions to ensure the units do not exceed permitted limits, and will remove a unit from service if required.

The NGS CTs are started and operated on No. 2 fuel oil.

All JEA units are operated under the boiler, turbine/generator, and operational guidelines as furnished by the manufacturers and JEA internal guidelines and procedures. Combustion turbine equipment is maintained under a preventative maintenance routine schedule as set forth in JEA's internal P.M. program.

When excessive emission conditions occur, the control room operator takes immediate corrective action.

When a unit shut down is required or unit trip occurs, the unit is brought down under established manufacturer and JEA operational procedures.

E.U. ID No.	Brief Description
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

SJRPP – Boiler No. 1 and Boiler No. 2

Startup and Shutdown Plans

Unit Startup

The SJRPP units utilize Electrostatic Precipitators for opacity control, Wet Limestone Scrubbers for sulfur dioxide control and staged combustion technologies for control of nitrogen oxides.

During startup, the SJRPP units initially utilize No. 2 Fuel Oil ignitors. Once steam quality and turbine conditions are sufficient, coal is introduced to the furnace and oil ignitors remain in service for flame stabilization at low burner capacities. Opacity is reduced to less than 20% through partial energization of precipitator fields after coal is introduced to the furnace and the precipitator reaches 200 F. After opacity is less than 20%, scrubber module(s) are placed in service to facilitate sulfur dioxide removal. After the precipitator has thermally soaked for two hours in excess of 200 F, additional precipitator fields may be energized to further reduce opacity and particulate burden to the scrubber.

Excessive NOx formation does not typically occur at low heat input levels associated with unit startup.

Unit Shut Down

Upon a unit shut-down or unit trip, automatic controls will abruptly isolate all fuel sources from the furnace, de-energize the precipitator and open the scrubber bypass. No further intentional combustion can occur until the furnace is sufficiently purged with air. The purging requirement is a requisite for the startup procedure to begin anew.

FACILITY-WIDE REPORTING REQUIREMENTS

(version dated 1/5/2011)

RR1. Reporting Schedule. This table summarizes information for convenience purposes only. It does not supersede any of the terms or conditions of this permit.

Report	Reporting Deadline(s)	Related Condition(s)
Plant Problems/Permit Deviations	Immediately upon occurrence (See RR2.d.)	RR2, RR3
Malfunction Excess Emissions Report	Quarterly (if requested)	RR3
Semi-Annual Monitoring Report	Every 6 months	RR4
Annual Operating Report	April 1	RR5
Annual Emissions Fee Form and Fee	March 1	RR6
Annual Statement of Compliance	Within 60 days after the end of each calendar year (or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement); and Within 60 days after submittal of a written agreement for transfer of responsibility, or Within 60 days after permanent shutdown.	RR7
Notification of Administrative Permit Corrections	As needed	RR8
Notification of Startup after Shutdown for More than One Year	Minimum of 60 days prior to the intended startup date or, if emergency startup, as soon as possible after the startup date is ascertained	RR9
Permit Renewal Application	225 days prior to the expiration date of permit	TV17
Test Reports	Maximum 45 days following compliance tests	TR8

{Permitting Note: See permit Section III. Emissions Units and Specific Conditions, for any additional Emission Unit-specific reporting requirements.}

RR2. Reports of Problems.

a. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules.

b. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(1) A description of and cause of noncompliance; and

(2) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

c. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

d. "Immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays; and, for purposes of Rule 62-4.160(15) and 40 CFR 70.6(a)(3)(iii)(B), "promptly" or "prompt" shall have the same meaning as "immediately".

[Rule 62-4.130, Rule 62-4.160(8), Rule 62-4.160(15), and Rule 62-213.440(1)(b), F.A.C.; 40 CFR 70.6(a)(3)(iii)(B)]

RR3. Reports of Deviations from Permit Requirements. The permittee shall report in accordance with the requirements of Rule 62-210.700(6), F.A.C. (below), and Rule 62-4.130, F.A.C. (condition RR2.), deviations from permit requirements, including those attributable to upset conditions as defined in the permit. Reports shall include the probable cause of such deviations, and any corrective actions or preventive measures taken. *Rule 62-210.700(6)*: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. (See condition RR2.). A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rules 62-213.440(1)(b)3.b., and 62-210.700(6)F.A.C.]

RR4. Semi-Annual Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports. [Rule 62-213.440(1)(b)3.a., F.A.C.]

RR5. Annual Operating Report.

a. The permittee shall submit to the Compliance Authority, each calendar year, on or before April 1, a completed DEP Form No 62-210.900(5), "Annual Operating Report for Air Pollutant Emitting Facility", for the preceding calendar year.

b. Emissions shall be computed in accordance with the provisions of Rule 62-210.370(2), F.A.C.

[Rules 62-210.370(2) & (3), and 62-213.440(3)(a)2., F.A.C.]

RR6. Annual Emissions Fee Form and Fee. Each Title V source permitted to operate in Florida must pay between January 15 and March 1 of each year, an annual emissions fee in an amount determined as set forth in Rule 62-213.205(1), F.A.C.

a. If the Department has not received the fee by February 15 of the year following the calendar year for which the fee is calculated, the Department will send the primary responsible official of the Title V source a written warning of the consequences for failing to pay the fee by March 1. If the fee is not postmarked by March 1 of the year due, the Department shall impose, in addition to the fee, a penalty of 50 percent of the amount of the fee unpaid plus interest on such amount computed in accordance with Section 220.807, F.S. If the Department determines that a submitted fee was inaccurately calculated, the Department shall either refund to the permittee any amount overpaid or notify the permittee of any amount underpaid. The Department shall not impose a penalty or interest on any amount underpaid, provided that the permittee has timely remitted payment of at least 90 percent of the amount determined to be due and remits full payment within 60 days after receipt of notice of the amount underpaid. The Department shall waive the collection of underpayment and shall not refund overpayment of the fee, if the amount is less than 1 percent of the fee due, up to $50.00. The Department shall make every effort to provide a timely assessment of the adequacy of the submitted fee. Failure to pay timely any required annual emissions fee, penalty, or interest constitutes grounds for permit revocation pursuant to Rule 62-4.100, F.A.C.

b. Any documentation of actual hours of operation, actual material or heat input, actual production amount, or actual emissions used to calculate the annual emissions fee shall be retained by the owner for a minimum of five (5) years and shall be made available to the Department upon request.

c. A completed DEP Form 62-213.900(1), "Major Air Pollution Source Annual Emissions Fee Form", must be submitted by a responsible official with the annual emissions fee.

[Rules 62-213.205(1), (1)(g), (1)(i) & (1)(j), F.A.C.]

RR7. Annual Statement of Compliance.

a. The permittee shall submit a Statement of Compliance with all terms and conditions of the permit that includes all the provisions of 40 CFR 70.6(c)(5)(iii), incorporated by reference at Rule 62-204.800, F.A.C., using DEP Form No. 62-213.900(7). Such statement shall be accompanied by a certification in accordance with Rule 62-213.420(4), F.A.C., for Title V requirements and with Rule 62-214.350, F.A.C., for Acid Rain requirements. Such statements shall be submitted (postmarked) to the Department and EPA:
   (1) Annually, within 60 days after the end of each calendar year during which the Title V permit was effective, or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement; and
   (2) Within 60 days after submittal of a written agreement for transfer of responsibility as required pursuant to 40 CFR 70.7(d)(1)(iv), adopted and incorporated by reference at Rule 62-204.800, F.A.C., or within 60 days after permanent shutdown of a facility permitted under Chapter 62-213, F.A.C.; provided that, in either such case, the reporting period shall be the portion of the calendar year the permit was effective up to the date of transfer of responsibility or permanent facility shutdown, as applicable.

b. In lieu of individually identifying all applicable requirements and specifying times of compliance with, non-compliance with, and deviation from each, the responsible official may use DEP Form No. 62-213.900(7) as such statement of compliance so long as the responsible official identifies all reportable deviations from and all instances of non-compliance with any applicable requirements and includes all information required by the federal regulation relating to each reportable deviation and instance of non-compliance.

c. The responsible official may treat compliance with all other applicable requirements as a surrogate for compliance with Rule 62-296.320(2), Objectionable Odor Prohibited.

[Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

RR8. Notification of Administrative Permit Corrections.

A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:

a. Typographical errors noted in the permit;
b. Name, address or phone number change from that in the permit;
c. A change requiring more frequent monitoring or reporting by the permittee;
d. A change in ownership or operational control of a facility, subject to the following provisions:
   (1) The Department determines that no other change in the permit is necessary;
   (2) The permittee and proposed new permittee have submitted an Application for Transfer of Air Permit, and the Department has approved the transfer pursuant to Rule 62-210.300(7), F.A.C.; and
   (3) The new permittee has notified the Department of the effective date of sale or legal transfer.
e. Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), adopted and incorporated by reference at Rule 62-204.800, F.A.C., and changes made pursuant to Rules 62-214.340(1) and (2), F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;
f. Changes listed at 40 CFR 72.83(a)(11) and (12), adopted and incorporated by reference at Rule 62-204.800, F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 62-210.360(1)(e), F.A.C.; and
g. Any other similar minor administrative change at the source.

[Rule 62-210.360, F.A.C.]

RR9. Notification of Startup. The owners or operator of any emissions unit or facility which has a valid air operation permit which has been shut down more than one year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of 60 days prior to the intended startup date.

a. The notification shall include information as to the startup date, anticipated emission rates or pollutants released, changes to processes or control devices which will result in changes to emission rates, and any other conditions which may differ from the valid outstanding operation permit.
b. If, due to an emergency, a startup date is not known 60 days prior thereto, the owner shall notify the Department as soon as possible after the date of such startup is ascertained.

[Rule 62-210.300(5), F.A.C.]

RR10. Report Submission. The permittee shall submit all compliance related notifications and reports required of this permit to the Compliance Authority. {See front of permit for address and phone number.}

RR11. EPA Report Submission. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to: Air, Pesticides & Toxics Management Division, United States Environmental Protection Agency, Region 4, Sam Nunn Atlanta Federal Center, 61 Forsyth Street SW, Atlanta, GA 30303-8960. Phone: 404/562-9077.

RR12. Acid Rain Report Submission. Acid Rain Program Information shall be submitted, as necessary, to: Department of Environmental Protection, 2600 Blair Stone Road, Mail Station #5510, Tallahassee, Florida 32399-2400. Phone: 850/488-6140. Fax: 850/922-6979.

RR13. Report Certification. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C. [Rule 62-213.440(1)(b)3.c, F.A.C.]

RR14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information. [Rule 62-213.420(4), F.A.C.]

RR15. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA. Any permittee may claim confidentiality of any data or other information by complying with this procedure. [Rules 62-213.420(2), and 62-213.440(1)(d)6., F.A.C.]

RR16. Forms and Instructions. The forms used by the Department in the Title V source operation program are adopted and incorporated by reference in Rule 62-213.900, F.A.C. The forms are listed by rule number, which is also the form number, and with the subject, title, and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resource Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, by contacting the appropriate permitting authority or by accessing the Department's web site at: http://www.dep.state.fl.us/air/rules/forms.htm.

a. Major Air Pollution Source Annual Emissions Fee Form (Effective 10/12/2008).
b. Statement of Compliance Form (Effective 06/02/2002).
c. Responsible Official Notification Form (Effective 06/02/2002).

[Rule 62-213.900, F.A.C.: Forms (1), (7) and (8)]

Table 6 (Revised) Part A

SJRPP PSD PERMIT
PSD-FL-010(C)

Table 6 – Part A

Emissions Unit	SO_2	NO_x	PM	Opacity (%)
Steam Generating Boiler No. 1 (6,144 MMBtu/hr maximum heat input)	4,669 lb/hr 0.76 lb/mmBtu (30-day rolling average)	3,686 lb/hr 0.6 lb/mmBtu	184 lb/hr 0.03 lb/mmBtu	20
Steam Generating Boiler No. 2 (6,144 MMBtu/hr maximum heat input)	4,669 lb/hr 0.76 lb/mmBtu (30-day rolling average)	3,686 lb/hr 0.6 lb/mmBtu	184 lb/hr 0.03 lb/mmBtu	20
Cooling Towers			67 lb/hr (each tower)	N/A

Table 6 (Revised) - Part B. SJRPP: Materials Handling and Storage Operations

Emission Unit No.	Materials Handling and Storage Operations Emission Unit/Point	Type Source	VE Limit % Opacity	AQCS	Predicted Emissions (lbs/hr)	VE Testing Frequency	Rationale
022: SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations							
022a	Gypsum Dewatering Building	Fugitive	5	1	0.04	Upon Request	Wet byproduct w/insignificant emissions
022a	Gypsum Storage Enclosure	Fugitive	5	1	0.008	Upon Request	Wet byproduct w/insignificant emissions
022j	Gypsum Truck Loadout	Fugitive	5	1	0.28	Upon Request	Wet byproduct w/insignificant emissions
022j	Fly Ash Loadout for Silo 1A (metal structure)	Fugitive	10	1 & 3	0.06	Upon Request	Emissions vented back to Saleable Ash Silo
022j	Fly Ash Loadout for Silo 1B (metal structure)	Fugitive	10	1 & 3	0.06	Upon Request	Emissions vented back to Saleable Ash Silo
022j	Fly Ash Loadout for Silo 2A (metal structure)	Fugitive	10	1 & 3	0.06	Upon Request	Emissions vented back to Saleable Ash Silo
022j	Fly Ash Loadout for Silo 2B (metal structure)	Fugitive	10	1 & 3	0.06	Upon Request	Emissions vented back to Saleable Ash Silo
022k	Solid Waste Disposal Area	Fugitive	10	1 & 2	0.31	Upon Request	Wet byproduct w/insignificant emissions
022l	*Saleable Fly Ash Silo 1A with Fabric Filter* *	Point-Vent	5	4 & 5	0.2	Annually	Vent with minor emissions
022l	*Saleable Fly Ash*	Point-Vent	5	4 & 5	0.2	Annually	Vent with minor

Table 6 (Revised) Part B

	*Silo 1B with Fabric Filter **						emissions
022l	*Saleable Fly Ash Silo 2A with Fabric Filter **	Point-Vent	5	4 & 5	0.2	Annually	Vent with minor emissions
022l	*Saleable Fly Ash Silo 2B with Fabric Filter **	Point-Vent	5	4 & 5	0.2	Annually	Vent with minor emissions
022l	*Non-Saleable Fly Ash Silo Unit 1-A with Fabric Filter **	Point-Vent	5	4 & 5	0.2	Annually	Vent with minor emissions
022l	*Non-Saleable Fly Ash Silo Unit 2-A with Fabric Filter **	Point-Vent	5	4 & 5	0.2	Annually	Vent with minor emissions
022m	*Wet Fly Ash Load out 1A/1B*	Fugitive	10	1, 4 & 6	0.2	Upon Request	Wet byproduct w/insignificant emissions
022m	Bottom Ash Loadouts 1A/1B	Fugitive	10	1	0.09	Upon Request	Wet byproduct w/insignificant emissions
022m	*Wet Fly Ash Load out 2A/2B*	Fugitive	10	1, 4 & 6	0.2	Upon Request	Wet byproduct w/insignificant emissions
022m	Bottom Ash Loadouts 2A/2B	Fugitive	10	1	0.09	Upon Request	Wet byproduct w/insignificant emissions
022n	Unpaved Road, By-Product Transport	Fugitive	10	1 & 2	0.58	Upon Request	No emission vent, reasonable precautions conducted (watering)

Table 6 (Revised) Part B

023: SJRPP: Fuel and Limestone Handling and Storage Operations

023a	Rotary Railcar Dumper Building	Point-Fugitive	10	1, 2, 4 & 6	0.15	Upon Request	No emissions vent, minor emissions, enclosed source w/spray bar
023b	Conveyor C-3 Tunnel Ventilation - 6,400 cfm; No control	Point-Vent	5	4	0.32	Upon Renewal of Title V	Provides tunnel ventilation only, minor emissions
023b	Conveyor C-3 Tunnel Ventilation - 6,400 cfm; No control	Point-Vent	5	1, 3 & 4	0.32	Upon Renewal of Title V	Provides tunnel ventilation only, minor emissions
023b	Conveyor C-3 Tunnel Ventilation - 21,600 cfm; No control	Point-Vent	5	1 & 4	0.32	Upon Renewal of Title V	Provides tunnel ventilation only, minor emissions
023c	Shiphold Operations	Fugitive	10	1, 4 & 6	0.54	Upon Request	No emissions vent, minor emissions
023d	Ship Unloader Hopper and Spillage Collector Transfers	Fugitive	10	1, 3, 4 & 6	0.28	Upon Request	No emissions vent, minor emissions
023d	Ship Unloader Hopper to Transfer CT-1, Spillage Conveyor	Fugitive	10	1, 3, 4 & 6	1	Upon Request	Enclosed conveyor, no emissions vent
023e	Fuel Transfer Building (DC-2)	Fugitive	10	1, 3 & 4	0.65	Upon Request	No emissions vent, minor emissions,

Table 6 (Revised) Part B

							enclosed source
023e	Transfer Station No. 1	Fugitive	5	1, 2 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 2	Fugitive	5	1, 2 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 3	Fugitive	5	1, 2 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 4	Fugitive	5	1 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 5	Fugitive	5	1 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 6	Fugitive	5	1 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 7	Fugitive	5	1 & 4	0.04	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Point 9GC-04 to 9GC-05	Fugitive	5	1	0.007	Upon Request	No emissions vent, minor emissions (gypsum)
023f	Stacker/Reclaimer (Stacker Mode)	Fugitive	10	1 & 3	2.29	Upon Request	No emissions vent, minor emissions
023f	Stacker	Fugitive	10	1 & 3	1.15	Upon Request	No emissions vent, minor emissions
023f	Reclaimer	Fugitive	10	1 & 3	0.43	Upon Request	No emissions vent, minor emissions
023g	Emergency Reclaim Hoppers	Fugitive	10	1	0.29	Upon Request	Same as other reclaim systems;

Table 6 (Revised) Part B

	- Loadout						not typically used
023j	Limestone Truck Loadout & Transfer	Fugitive	10	1	0.1	Upon Request	No emissions vent, minor emissions.
023k	Limestone Storage Pile #1 - Existing	Fugitive	10	1	0.26	Upon Request	No emissions location, minor emissions
023k	Limestone Storage Pile #2 - Fuel Yard	Fugitive	10	1, 2 & 3	0.71	Upon Request	No emissions location, minor emissions.
023k	Limestone Reclaim Loadout - Grizzley	Fugitive	10	1 & 3	None	Upon Request	Minor emissions
023k	Coal Pile	Fugitive	10	1, 2 & 3	0.26	Upon Request	No emissions location, minor emissions
023k	Petroleum Coke Pile	Fugitive	10	1, 2 & 3	0.71	Upon Request	No emissions location, minor emissions
023l	Limestone Reclaim Hopper with Fabric Filter (3DC-01)	Point-Vent	5	1, 4 & 5	0.14	Annually	Vent with minor emissions
023l	Limestone Silos with Fabric Filters (2: 1DC-01 and 2DC-01)	Point-Vent	5	1, 4 & 5	0.05	Annually	Minor emissions
023l	Quick Lime Silo with Filter Vent (used for water treatment)	Point-Vent	5	4 & 5	None	Upon Renewal of Title V	Minor emission source, low volume material handling; 15 min VE suggested
023l	Fuel Handling Building with Fabric Filter (DC-3)	Point-Vent	5	1, 4 & 5	0.24	Annually	Vent with minor emissions

Table 6 (Revised) Part B

0231	Unit #1 Fuel Storage Bins with Fabric Filter (DC-4)	Point-Vent	5	1, 4 & 5	0.009	Annually	Vent with minor emissions
0231	Unit #2 Fuel Storage Bins with Fabric Filter (DC-5)	Point-Vent	5	1, 4 & 5	0.009	Annually	Vent with minor emissions

NOTES:

a. "*Italics*" indicates that the emission point was not included in Revised Table 6 of PSD-FL-010(C), but is associated with the material handling and storage operations at JEA's SJRPP.

b. The VE limit (% opacity) shall be used for compliance purposes and demonstrated using EPA Reference Method 9, pursuant to 40 CFR Part 60, Appendix A, and Chapter 62-297, F.A.C.

c. **Air Quality Control Systems (AQCS)**

1. Conditioned Materials
2. Wet Suppression, as needed
3. Water Sprays, as needed
4. Enclosures (Total, Partial, Covers, & Wind Screens)
5. Dust Control System - AQCS
6. Best Operating Practices

d. Predicted emissions (lbs/hr): these values were predicted/estimated and used in a preliminary screening/modeling evaluation for as permitting action (PSD-FL-010) and are not considered to be allowable emission limits.

* Concrete Structure.

FACILITY-WIDE TESTING REQUIREMENTS

(version dated 9/12/2008)

Unless otherwise specified in the permit, the following testing requirements apply to each emissions unit for which testing is required. The terms "stack" and "duct" are used interchangeably in this appendix.

TR1. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

TR2. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

TR3. Calculation of Emission Rate. For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

TR4. Applicable Test Procedures.

a. *Required Sampling Time.*

(1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

(2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

(a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

(b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

(c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

b. *Minimum Sample Volume*. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Required Flow Rate Range*. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

d. *Calibration of Sampling Equipment*. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

TABLE 297.310-1 CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/- 0.001" mean of at least three readings; Max. deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

e. *Allowed Modification to EPA Method 5*. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TR5. Determination of Process Variables.

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

TR6. Sampling Facilities. Permittees that are required to sample mass emissions from point sources shall install stack sampling ports and provide sampling facilities that meet the requirements of this condition. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the

stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

TR7. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*

(1) The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

(2) For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

(3) The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   (a) Did not operate; or
   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

(4) During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   (a) Visible emissions, if there is an applicable standard;
   (b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   (c) Each NESHAP pollutant, if there is an applicable emission standard.

(5) An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

(6) For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

(7) For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

(8) Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

(9) The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(10) An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

c. *Waiver of Compliance Test Requirements.* If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in

Rule 62-297.620, F.A.C., that the compliance the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.]

TR8. Test Reports.

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

(1) The type, location, and designation of the emissions unit tested.
(2) The facility at which the emissions unit is located.
(3) The owner or operator of the emissions unit.
(4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
(5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
(6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
(7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
(8) The date, starting time and duration of each sampling run.
(9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
(10) The number of points sampled and configuration and location of the sampling plane.
(11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
(12) The type, manufacturer and configuration of the sampling equipment used.
(13) Data related to the required calibration of the test equipment.
(14) Data on the identification, processing and weights of all filters used.
(15) Data on the types and amounts of any chemical solutions used.
(16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
(17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
(18) All measured and calculated data required to be determined by each applicable test procedure for each run.
(19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
(20) The applicable emission standard and the resulting maximum allowable emission rate for the

emissions unit plus the test result in the same form and unit of measure.

(21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

TITLE V GENERAL CONDITIONS
(version dated 11/01/2010)

Operation

TV1. General Prohibition. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit. [Rule 62-4.030, Florida Administrative Code (F.A.C.)]

TV2. Validity. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department. [Rule 62-4.160(2), F.A.C.]

TV3. Proper Operation and Maintenance. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules. [Rule 62-4.160(6), F.A.C.]

TV4. **Not Federally Enforceable.** Health, Safety and Welfare. To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution, shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. [Rule 62-4.050(3), F.A.C.]

TV5. Continued Operation. An applicant making timely and complete application for permit, or for permit renewal, shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, and in accordance with applicable requirements of the Acid Rain Program and applicable requirements of the CAIR Program, until the conclusion of proceedings associated with its permit application or until the new permit becomes effective, whichever is later, provided the applicant complies with all the provisions of subparagraphs 62-213.420(1)(b)3., F.A.C. [Rules 62-213.420(1)(b)2., F.A.C.]

TV6. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation:

a. Permitted sources may change among those alternative methods of operation allowed by the source's permit as provided by the terms of the permit;
b. A permitted source may implement operating changes, as defined in Rule 62-210.200, F.A.C., after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
   (1) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
   (2) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
c. Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.

[Rule 62-213.410, F.A.C.]

TV7. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

Compliance

TV8. Compliance with Chapter 403, F.S., and Department Rules. Except as provided at Rule 62-213.460, Permit Shield, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules. [Rule 62-4.070(7), F.A.C.]

TV9. Compliance with Federal, State and Local Rules. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of a facility or an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law. [Rule 62-210.300, F.A.C.]

TV10. Binding and enforceable. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions. [Rule 62-4.160(1), F.A.C.]

TV11. Timely information. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly. [Rule 62-4.160(15), F.A.C.]

TV12. Halting or reduction of source activity. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity. [Rule 62-213.440(1)(d)3., F.A.C.]

TV13. Final permit action. Any Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C. [Rule 62-213.440(1)(d)4., F.A.C.]

TV14. Sudden and unforeseeable events beyond the control of the source. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference. [Rule 62-213.440(1)(d)5., F.A.C.]

TV15. 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 this condition 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 or the CAIR Program. [Rule 62-213.460, F.A.C.]

TV16. Compliance With Federal Rules. A facility or emissions unit subject to any standard or requirement of 40 CFR, Part 60, 61, 63 or 65, adopted and incorporated by reference at Rule 62-204.800, F.A.C., shall comply with such standard or requirement. Nothing in this chapter shall relieve a facility or emissions unit from complying with such standard or requirement, provided, however, that where a facility or emissions unit is subject to a standard established in Rule 62-296, F.A.C., such standard shall also apply. [Rule 62-296.100(3), F.A.C.]

Permit Procedures

TV17. Permit Revision Procedures. The permittee shall revise its permit as required by Rules 62-213.400, 62-213.412, 62-213.420, 62-213.430 & 62-4.080, F.A.C.; and, in addition, the Department shall revise permits as provided in Rule 62-4.080, F.A.C. & 40 CFR 70.7(f).

TV18. Permit Renewal. The permittee shall renew its permit as required by Rules 62-4.090, 62.213.420(1) and 62-213.430(3), F.A.C. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) [Application for Air Permit - Long Form], 62-213.420(3) [Required Information], 62-213.420(6) [CAIR Part Form], F.A.C. Unless a Title V source submits a timely and complete application for permit renewal in accordance with the requirements this rule, the existing permit shall expire and the source's right to operate shall terminate. For purposes of a permit renewal, a timely application is one that is submitted 225 days before the expiration of a permit that expires on or after June 1, 2009. No Title V permit will be issued for a new term except through the renewal process. [Rules 62-213.420 & 62-213.430, F.A.C.]

TV19. Insignificant Emissions Units or Pollutant-Emitting Activities. The permittee shall identify and evaluate insignificant emissions units and activities as set forth in Rule 62-213.430(6), F.A.C.

TV20. Savings Clause. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect. [Rule 62-213.440(1)(d)1., F.A.C.]

TV21. Suspension and Revocation.

a. Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.
b. Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.
c. A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or his agent:
    (1) Submitted false or inaccurate information in his application or operational reports.
    (2) Has violated law, Department orders, rules or permit conditions.
    (3) Has failed to submit operational reports or other information required by Department rules.
    (4) Has refused lawful inspection under Section 403.091, F.S.
d. No revocation shall become effective except after notice is served by personal services, certified mail, or newspaper notice pursuant to Section 120.60(5), F.S., upon the person or persons named therein and a hearing held if requested within the time specified in the notice. The notice shall specify the provision of the law, or rule alleged to be violated, or the permit condition or Department order alleged to be violated, and the facts alleged to constitute a violation thereof.

[Rule 62-4.100, F.A.C.]

TV22. Not federally enforceable. Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules. [Rule 62-4.110, F.A.C.]

TV23. Emissions Unit Reclassification.

a. Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.
b. If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.

[Rule 62-210.300(6), F.A.C.]

TV24. Transfer of Permits. Per Rule 62-4.160(11), F.A.C., this permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility. The permittee shall also comply with the requirements of Rule 62-210.300(7), F.A.C., and use DEP Form No. 62-210.900(7). [Rules 62-4.160(11), 62-4.120, and 62-210.300(7), F.A.C.]

Rights, Title, Liability, and Agreements

TV25. Rights. As provided in Subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit. [Rule 62-4.160(3), F.A.C.]

TV26. Title. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. [Rule 62-4.160(4), (F.A.C.]

TV27. Liability. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department. [Rule 62-4.160(5), F.A.C.]

TV28. Agreements.

a. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:
   (1) Have access to and copy any records that must be kept under conditions of the permit;
   (2) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,
   (3) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.
b. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
c. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

[Rules 62-4.160(7), (9), and (10), F.A.C.]

Recordkeeping and Emissions Computation

TV29. Permit. The permittee shall keep this permit or a copy thereof at the work site of the permitted activity. [Rule 62-4.160(12), F.A.C.]

TV30. Recordkeeping.

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These

materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:
   (1) The date, exact place, and time of sampling or measurements, and the operating conditions at the time of sampling or measurement;
   (2) The person responsible for performing the sampling or measurements;
   (3) The dates analyses were performed;
   (4) The person and company that performed the analyses;
   (5) The analytical techniques or methods used;
   (6) The results of such analyses.

[Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

TV31. Emissions Computation. Pursuant to Rule 62-210.370, F.A.C., the following required methodologies are to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with Rule 62-210.370, F.A.C. Rule 62-210.370, F.A.C., is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

For any of the purposes specified above, the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

a. *Basic Approach.* The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
   (1) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
   (2) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
   (3) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

b. *Continuous Emissions Monitoring System (CEMS).*
   (1) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
      (a) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or,
      (b) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.
   (2) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

(a) A calibrated flowmeter that records data on a continuous basis, if available; or
(b) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(3) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

c. *Mass Balance Calculations.*

(1) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:
(a) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and,
(b) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(2) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(3) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

d. *Emission Factors.*

(1) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.
(a) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
(b) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.
(c) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

(2) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

e. *Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS.* In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.
f. *Accounting for Emissions During Periods of Startup and Shutdown.* In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.
g. *Fugitive Emissions.* In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.
h. *Recordkeeping.* The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(1) & (2), F.A.C.]

Responsible Official

TV32. Designation and Update. The permittee shall designate and update a responsible official as required by Rule 62-213.202, F.A.C.

Prohibitions and Restrictions

TV33. Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source. [40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

TV34. Refrigerant Requirements. Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Chapter 62-281, F.A.C.

TV35. Open Burning Prohibited. Open burning is prohibited unless performed in accordance with the provisions of Rule 62-296.320(3) or Chapter 62-256, F.A.C.

TV36. Heavy-Duty Vehicle Idling Reduction. The permittee shall only allow idling of heavy-duty diesel engine powered motor vehicles in accordance with the following provisions:

a. *Applicability.* This rule applies to any heavy-duty diesel engine powered motor vehicle. For the purposes of this rule:
   (1) Heavy-duty diesel engine powered motor vehicle means a motor vehicle:
      (a) With a gross vehicle weight rating equal to or greater than 8,500 pounds;
      (b) Used on roads for the transportation of passengers or freight; and
      (c) Serving a commercial, governmental, or public purpose.
   (2) Gross vehicle weight rating means the value specified by the manufacturer as the maximum design loaded weight of a single vehicle.
b. *Requirement.* Owners or operators of heavy-duty diesel engine powered motor vehicles are prohibited from idling for more than five consecutive minutes. Idling is the continuous operation of a vehicle's main drive engine while the vehicle is stopped.
c. *Exemptions.* The idling restriction of subsection 62-285.420(2), F.A.C., shall not apply:

(1) To idling while stopped for traffic conditions over which the driver has no control, including being stopped for an official traffic control device or signal, in a line of traffic, at a railroad crossing, at a construction zone, or at the direction of law enforcement;
(2) To idling of buses 10 minutes prior to passenger loading and when passengers are onboard if needed for passenger comfort;
(3) To idling of an armored vehicle in which a person remains inside the vehicle while guarding the contents of the vehicle or while the vehicle is being loaded or unloaded.
(4) If idling is necessary for a police, fire, ambulance, public safety, military, or other vehicle being used in an emergency or training capacity;
(5) If idling is necessary to verify that the vehicle is in safe operating condition as required by law and that all equipment is in good working order, either as part of a daily vehicle inspection or as otherwise needed, provided that engine idling is mandatory for such verification;
(6) If idling is necessary to accomplish work for which the vehicle was designed, other than propulsion, for example: collecting solid waste or recyclable material; controlling cargo temperature; or operating a lift, crane, pump, drill, hoist, mixer, or other auxiliary equipment other than a heater or air conditioner;
(7) If idling is necessary to operate defrosters, heaters, air conditioners, or other equipment to prevent a safety or health emergency, but not solely for the comfort of the driver;
(8) To idling while the driver is sleeping or resting in a sleeper berth. This exemption expires at midnight September 30, 2013.

[Rule 62-285.420, F.A.C.

APPENDIX U

LIST OF UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES

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

E.U. No.	***Brief Description***
The following Storage Tanks are located at the Northside Generating Station (NGS)	
-010	Bunker C Storage Tanks
-010	Storage Tank: 4,578,000 gallons - Bunker C
-010	Storage Tank: 4,578,000 gallons - Bunker C
-010	Storage Tank: 4,578,000 gallons - Bunker C
-010	Storage Tank: 11,256,000 gallons - Bunker C
-010	Storage Tank: 11,256,000 gallons - Bunker C
-010	Storage Tank: 11,256,000 gallons - Bunker C
-011	Diesel Storage Tanks
-011	Storage Tank #10: 168,000 gallons - Diesel
-011	Storage Tank #11: 4,200,000 gallons - Diesel
-011	Storage Tank #12: 4,200,000 gallons - Diesel
-012	Diesel Storage Tanks
-012	Storage Tank #13: 4,200,000 gallons - Diesel
-012	Storage Tank #14: 4,200,000 gallons - Diesel
-015	Waste Oil Storage Tanks
-015	Storage Tank: 750 gallons - Waste Oil Storage (Unit 1)
-015	Storage Tank: 1,000 gallons - Waste Oil Storage (Unit 2)
-015	Storage Tank: 575 gallons - Waste Oil Storage (Unit 3)
The following Storage Tanks are located at the St. Johns River Power Park (SJRPP)	
-019	Storage Tank: 636,106 gallons - Diesel
-020	Storage Tank: 10,069 gallons - Gasoline
-021	Storage Tank - Emergency Fire Pump: 1,123 gallons - Diesel
-021	Storage Tank - AQCS Emergency Generator Day Tank: 561 gallons - Diesel
-021	Storage Tank - Coal/Limestone Fuel Storage: 10,069 gallons - Diesel
-021	Storage Tank - Ash Landfill Fuel Storage: 10,069 gallons - Diesel
-021	Storage Tank - Power Block Emergency Generator Fuel Storage : 4,015 gallons - Diesel
-021	Storage Tank: 3,000 gallons - Diesel

REFERENCED ATTACHMENTS

The Following Attachments Are Included for Applicant Convenience:

Table H, Permit History.

TABLE H
PERMIT HISTORY/ID NUMBER CHANGES

Relevant Permits Issued & Projects:

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
All	Facility	0310045-001-AV	01/01/1999	12/31/2003	Initial
All	Facility	0310045-011-AV	01/01/2004	12/31/2008	1st Renewal
All	Facility	0310045-016-AV	06/20/2006	NA	Revision
All	Facility	0310045-020-AV[4]	01/01/2009	12/31/2013	2nd Renewal
		0310045-028-AV	12/10/2010	NA	Revision
-016, -017	SJRPP: SCR on Boiler Nos. 1 & 2	0310045-017-AC	02/28/2007	06/30/2009	Construction (mod.)
		-018-AV	Subsumed into -020-AV	Subsumed into -020-AV	Revision (CAIR)
		0310045-019-AV	Withdrawn	Withdrawn	Revision (CAMR)
-029, -031	NGS: Material Handling Operations	0310045-021-AC/PSD-FL-265D	11/10/2008	NA	Construction (mod.)
-027, -026	NGS: CFB Units 1 & 2 - Spray Dryer Absorber Maintenance	0310045-022-AC/PSD-FL-265E	02/06/2009	NA	Construction (mod.)
-027, -026	NGS: CFB Units 1 & 2 Fuel Additives - Generic Emissions Unit Exemption	0310045-023-AC/PSD-FL-265F	11/20/2008	NA	Construction (mod.)
-016, -017	SJRPP: Natural Gas Igniters/Fuel Oil Igniters on Boiler Nos. 1 & 2	0310045-024-AC/PSD-FL-010H	11/21/2008	NA	Construction (mod.)
-016, -017	SJRPP: SCR on Boiler Nos. 1 & 2	0310045-025-AC (Extends 0310045-017-AC)	06/04/2009	12/31/2009	NA
-003	NGS: Unit 3 Revised Refurbishment Project	0310045-026-AC	02/09/2010	09/01/2011	Construction (mod.)
-003	NGS: Unit 3 Title V Revision to incorporate Project 026-AC	0310045-030-AV	06/23/2011	12/31/2013	Revision
-027, -026	NGS: CFB Units 1 & 2 Landfill Gas Combustion	0310045-027-AC	12/13/2010	06/30/2011	Construction (mod.)
-016, -017	SJRPP: Boiler Nos. 1 & 2 Natural Gas Combustion	0310045-029-AC/PSD-FL-010I	07/08/2010	06/30/2011	Construction (mod.)
-016, -017	Revision to incorporate Permit No. 0310045-029-AC/PSD-FL-010I	NA	Subsumed into -028-AV	Subsumed into -028-AV	Revision
-022	SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations	PSD-FL-010/PA 81-13	03/12/1982; 10/28/1986	NA	Construction (mod.)
		0310045-012-AC/PSD-FL-010E	11/04/2003	12/31/2008	Construction (mod.)
		0310045-015-AC/PSD-FL-010G	04/07/2006	12/31/2008	Construction (mod.)

TABLE H

PERMIT HISTORY/ID NUMBER CHANGES

Relevant Permits Issued & Projects:

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
All	Facility	0310045-001-AV	01/01/1999	12/31/2003	Initial
All	Facility	0310045-011-AV	01/01/2004	12/31/2008	1st Renewal
All	Facility	0310045-016-AV	06/20/2006	NA	Revision
All	Facility	0310045-020-AV[4]	01/01/2009	12/31/2013	2nd Renewal
		0310045-028-AV	12/10/2010	NA	Revision
-016, -017	SJRPP: SCR on Boiler Nos. 1 & 2	0310045-017-AC	02/28/2007	06/30/2009	Construction (mod.)
		-018-AV	Subsumed into -020-AV	Subsumed into -020-AV	Revision (CAIR)
		0310045-019-AV	Withdrawn	Withdrawn	Revision (CAMR)
-029, -031	NGS: Material Handling Operations	0310045-021-AC/PSD-FL-265D	11/10/2008	NA	Construction (mod.)
-027, -026	NGS: CFB Units 1 & 2 - Spray Dryer Absorber Maintenance	0310045-022-AC/PSD-FL-265E	02/06/2009	NA	Construction (mod.)
-027, -026	NGS: CFB Units 1 & 2 Fuel Additives - Generic Emissions Unit Exemption	0310045-023-AC/PSD-FL-265F	11/20/2008	NA	Construction (mod.)
-016, -017	SJRPP: Natural Gas Igniters/Fuel Oil Igniters on Boiler Nos. 1 & 2	0310045-024-AC/PSD-FL-010H	11/21/2008	NA	Construction (mod.)
-016, -017	SJRPP: SCR on Boiler Nos. 1 & 2	0310045-025-AC (Extends 0310045-017-AC)	06/04/2009	12/31/2009	NA
-003	NGS: Unit 3 Revised Refurbishment Project	0310045-026-AC	02/09/2010	09/01/2011	Construction (mod.)
-003	NGS: Unit 3 Title V Revision to incorporate Project 026-AC	0310045-030-AV	06/23/2011	12/31/2013	Revision
-027, -026	NGS: CFB Units 1 & 2 Landfill Gas Combustion	0310045-027-AC	12/13/2010	06/30/2011	Construction (mod.)
-016, -017	SJRPP: Boiler Nos. 1 & 2 Natural Gas Combustion	0310045-029-AC/PSD-FL-010I	07/08/2010	06/30/2011	Construction (mod.)
-016, -017	Revision to incorporate Permit No. 0310045-029-AC/PSD-FL-010I	NA	Subsumed into -028-AV	Subsumed into -028-AV	Revision
-022	SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations	PSD-FL-010/PA 81-13	03/12/1982; 10/28/1986	NA	Construction (mod.)
		0310045-012-AC/PSD-FL-010E	11/04/2003	12/31/2008	Construction (mod.)
		0310045-015-AC/PSD-FL-010G	04/07/2006	12/31/2008	Construction (mod.)

TABLE H

PERMIT HISTORY/ID NUMBER CHANGES

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
		0310045-016-AV	06/20/2006	12/31/2008	Revision
-023	SJRPP: Fuel and Limestone Handling and Storage Operations	0310045-015-AC/PSD-FL-010G	04/07/2006	12/31/2008	Construction (mod.)
		0310045-016-AV	06/20/2006	12/31/2008	Revision
-026	NGS Circulating Fluidized Bed (CFB) Boiler No. 2	0310045-003-AC/PSD-FL-265	05/25/2001	05/25/2006	Construction (new)
		0310047-007-AC/PSD-FL-265A	04/25/2002	12/31/2003	Construction (mod.)
		0310045-012-AC/PSD-FL-265B	11/04/2003	12/31/2008	Construction (mod.)
		0310045-015-AC/PSD-FL-265C	04/07/2006	12/31/2008	Construction (mod.)
		0310045-016-AV	06/20/2006	12/31/2008	Revision
-027	NGS CFB Boiler No. 1	0310045-003-AC/PSD-FL-265	05/25/2001	05/25/2006	Construction (new)
		0310047-007-AC	04/25/2002	12/31/2003	Construction (mod.)
		0310045-012-AC/PSD-FL-265B	11/04/2003	12/31/2008	Construction (mod.)
		0310045-015-AC/PSD-FL-265C	04/07/2006	12/31/2008	Construction (mod.)
		0310045-016-AV	06/20/2006	12/31/2008	Revision
-044 thru -050	STI Operations [3]	0310045-016-AV	06/20/2006	12/31/2008	Revision
-016 & -017	SJRPP Boiler Nos. 1 & 2	PA 81-13			

[1] St. Johns River Power Park (SJRPP).
[2] Northside Generating Station (NGS) Combustion Turbine (CT).
[3] Separations Technology, LLC (ST)
[4] the most recently posted Title V permit on the web site.
"NA" represents not applicable.

Scearce, Lynn

From: Scearce, Lynn
Sent: Tuesday, July 05, 2011 3:03 PM
To: 'chanjm@jea.com'
Cc: 'brosm@jea.com'; 'GianNB@jea.com'; 'ken.kosky@golder.com'; 'tilley@coj.net'; 'forney.kathleen@epa.gov'; 'oquendo.ana@epa.gov'; 'Friday, Barbara'; 'Gibson, Victoria'; Lanh, Kris; Koerner, Jeff
Subject: NORTHSIDE/SJRPP; 0310045-030-AV
Attachments: 0310045_030_AV_signatures.pdf

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0310045.030.AV.F_pdf.zip

Owner/Company Name: JEA
Facility Name: NORTHSIDE/SJRPP
Project Number: 0310045-030-AV
Permit Status: FINAL
Permit Activity: PERMIT REVISION
Facility County: DUVAL

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp.

Permit project documents addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Lynn Scearce, 850-717-9025

Division of Air Resource Management (DARM)

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> .

Scearce, Lynn

From: Scearce, Lynn
Sent: Tuesday, July 05, 2011 3:03 PM
To: 'chanjm@jea.com'
Cc: 'brosm@jea.com'; 'GianNB@jea.com'; 'ken.kosky@golder.com'; 'tilley@coj.net'; 'forney.kathleen@epa.gov'; 'oquendo.ana@epa.gov'; 'Friday, Barbara'; 'Gibson, Victoria'; Lanh, Kris; Koerner, Jeff
Subject: NORTHSIDE/SJRPP; 0310045-030-AV
Attachments: 0310045_030_AV_signatures.pdf

Tracking:

Recipient	Delivery	Read
'chanjm@jea.com'		✓
'brosm@jea.com'	✓	✓ received; reviewed
~~'GianNB@jea.com'~~		
Ken Kosky 'ken.kosky@golder.com'		✓
'tilley@coj.net'	✓	
'forney.kathleen@epa.gov'		
'oquendo.ana@epa.gov'		
'Friday, Barbara'		Read: 7/6/2011 7:36 AM
'Gibson, Victoria'		Read: 7/5/2011 3:20 PM
Lanh, Kris	Delivered: 7/5/2011 3:03 PM	Read: 7/5/2011 3:16 PM
Koerner, Jeff	Delivered: 7/5/2011 3:03 PM	Read: 7/5/2011 3:29 PM
Friday, Barbara	Delivered: 7/5/2011 3:03 PM	
Gibson, Victoria	Delivered: 7/5/2011 3:03 PM	

Dear Sir/ Madam:

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Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0310045.030.AV.F_pdf.zip

Owner/Company Name: JEA
Facility Name: NORTHSIDE/SJRPP
Project Number: 0310045-030-AV
Permit Status: FINAL
Permit Activity: PERMIT REVISION
Facility County: DUVAL

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Permit project documents addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Lynn Scearce, 850-717-9025

Division of Air Resource Management (DARM)

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> .

Scearce, Lynn

From: Gianazza, N. Bert [GianNB@jea.com]
Sent: Wednesday, July 06, 2011 8:12 AM
To: Scearce, Lynn
Cc: Chansler, James M. - Chief Operating Officer; Holbrooks, Kevin E. - Director, Compliance; Mann, Athena T. - Vice President, Environmental Services
Subject: RE: NORTHSIDE/SJRPP; 0310045-030-AV

Lynn,

We have received the documents and can view them.

Thanks, Bert

From: Scearce, Lynn [mailto:Lynn.Scearce@dep.state.fl.us]
Sent: Tuesday, July 05, 2011 3:03 PM
To: Chansler, James M. - Chief Operating Officer
Cc: brosm@jea.com; Gianazza, N. Bert; ken.kosky@golder.com; tilley@coj.net; forney.kathleen@epa.gov; oquendo.ana@epa.gov; Friday, Barbara; Gibson, Victoria; Lanh, Kris; Koerner, Jeff
Subject: NORTHSIDE/SJRPP; 0310045-030-AV

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0310045.030.AV.F_pdf.zip

Owner/Company Name: JEA
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Project Number: 0310045-030-AV
Permit Status: FINAL
Permit Activity: PERMIT REVISION
Facility County: DUVAL

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Lynn Scearce, 850-717-9025

Division of Air Resource Management (DARM)

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The Department of Environmental Protection values your feedback as a customer. DEP Secretary Herschel T. Vinyard Jr. is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Scearce, Lynn

From: Microsoft Exchange
To: tilley@coj.net
Sent: Tuesday, July 05, 2011 3:04 PM
Subject: Relayed: NORTHSIDE/SJRPP; 0310045-030-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

tilley@coj.net

Subject: NORTHSIDE/SJRPP; 0310045-030-AV

Sent by Microsoft Exchange Server 2007

Scearce, Lynn

From: Chansler, James M. - Chief Operating Officer [ChanJM@jea.com]
To: Scearce, Lynn
Sent: Tuesday, July 05, 2011 3:09 PM
Subject: Read: NORTHSIDE/SJRPP; 0310045-030-AV

Your message was read on Tuesday, July 05, 2011 3:08:38 PM (GMT-05:00) Eastern Time (US & Canada).

Scearce, Lynn

From: Kosky, Ken [Ken_Kosky@golder.com]
To: Scearce, Lynn
Sent: Tuesday, July 05, 2011 3:20 PM
Subject: Read: NORTHSIDE/SJRPP; 0310045-030-AV

Your message was read on Tuesday, July 05, 2011 3:19:33 PM (GMT-05:00) Eastern Time (US & Canada).