



## Memorandum

# Florida Department of Environmental Protection

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TO: Joseph Kahn, Division of Air Resource Management  
THROUGH: Trina Vielhauer, Bureau of Air Regulation   
Jon Holtom, Title V Section  
FROM: Tom Cascio   
DATE: 12/10/08  
SUBJECT: Title V Air Operation Permit No. 0810010-014-AV

Florida Power and Light Company  
Manatee Power Plant  
Final Title V Air Operation Permit Renewal

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

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

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

Attachments

## NOTICE OF FINAL PERMIT

*In the Matter of an  
Application for Permit by:*

Florida Power and Light Company  
19050 State Road 62  
Parrish, Florida 34219-9220

Permit No. 0810010-014-AV  
Manatee Power Plant  
Title V Air Operation Permit Renewal  
Manatee County

*Responsible Official:*

Mr. Paul Plotkin, Plant General Manager

Enclosed is the final permit package to renew the Title V air operation permit for the Manatee Power Plant. The existing facility is located in Manatee County, at 19050 State Road 62, in Parrish, 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.



Trina Vielhauer, Chief  
Bureau of Air Regulation

TLV/jkh/tbc

### 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. Paul Plotkin, Florida Power and Light Company: [pplotkin@fpl.com](mailto:pplotkin@fpl.com)

Mr. Kennard Kosky, P.E., Golder Associates: [kkosky@golder.com](mailto:kkosky@golder.com)

Ms. Sheila M. Wilkinson, Florida Power and Light Company: [Sheila\\_Wilkinson@fpl.com](mailto:Sheila_Wilkinson@fpl.com)

Ms. Mara Nasca, Southwest District Office: [mara.nasca@dep.state.fl.us](mailto:mara.nasca@dep.state.fl.us)

Ms. Katy Forney, US EPA Region 4: [forney.kathleen@epa.gov](mailto:forney.kathleen@epa.gov)

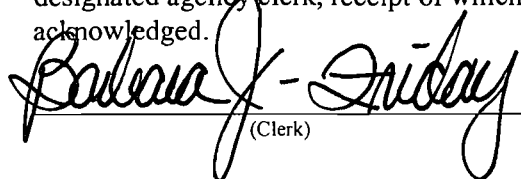
Ms. Ana Oquendo, US EPA Region 4: [oquendo.ana@epa.gov](mailto:oquendo.ana@epa.gov)

Ms. Barbara Friday, DEP BAR: [Barbara.Friday@dep.state.fl.us](mailto: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](mailto: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.

 12/12/08  
(Clerk) (Date)

## **FINAL DETERMINATION**

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### **PERMITTEE**

Florida Power and Light Company  
19050 State Road 62  
Parrish, Florida 34219-9220

### **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. 0810010-014-AV  
Manatee Power Plant

The purpose of this project is to renew the Title V air operation permit for the Manatee Power Plant.

### **NOTICE AND PUBLICATION**

The Department distributed an Intent to Issue a Title V Air Operation Permit Renewal package on October 29, 2008. The applicant published the Public Notice of Intent to Issue a Title V Air Operation Permit Renewal in the Bradenton Herald on November 4, 2008. The Department received the proof of publication on November 10, 2008. A proposed permit was issued for EPA review on December 5, 2008.

### **COMMENTS**

No comments on the proposed permit were received from the EPA Region 4 Office.

### **CONCLUSION**

The final action of the Department is to issue the permit with no changes.

## STATEMENT OF BASIS

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### Title V Air Operation Permit Renewal Permit No. 0810010-014-AV

#### APPLICANT

The applicant for this project is Florida Power and Light Company. The applicant's responsible official and mailing address are: Mr. Paul Plotkin, Plant General Manager, Manatee Plant, 19050 State Road 62, Parrish, Florida 34219-9220.

#### FACILITY DESCRIPTION

The applicant operates the Manatee Power Plant, which is located at 19050 State Road 62, Parrish, in Manatee County, Florida.

This nominal 2,750 megawatt (MW) facility consists of two fossil fuel steam generators, a "4-on-1" gas-fired combined cycle unit and associated support equipment.

Fossil Fuel Steam Generators, Unit 1 and Unit 2: Each unit is a Foster-Wheeler Steam Generator rated at 800 MW (900 MW gross capacity) output. These units burn a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from Florida Power and Light Company (FPL) operations, discharging pollutants through a stack 499 feet above ground level. Each unit is equipped with multiple cyclones, a flue gas recirculation system and staged combustion and also operates a Westinghouse tandem compound, reheat-type extraction turbine.

Combined Cycle Gas Turbine, Unit 3: This unit consists of four ("4-on-1") nominal 170 MW General Electric Model PG7241(FA) gas-fired turbine-electrical generator sets with evaporative inlet cooling systems, an automated gas turbine control system, an inlet air filtration system, four 495 million British thermal units per hour (MMBtu/hr) supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors, a single nominal 470 MW steam-electrical generator that serves all four gas turbine/HRSG systems, four 120 feet high exhaust stacks, and associated support equipment. The total generating capacity of the "4-on-1" combined cycle system Unit 3 is 1150 MW.

#### PROJECT DESCRIPTION

The purpose of this permitting project is to renew the existing Title V air operation permit for the above referenced facility.

#### PROCESSING SCHEDULE AND RELATED DOCUMENTS

Application for a Title V air operation permit renewal received July 3, 2008.

#### PRIMARY REGULATORY REQUIREMENTS

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

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

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

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

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

CAM: The facility is not subject to compliance assurance monitoring (CAM). The mechanical dust collectors of Units 1 and 2 are excluded from CAM, because they are (a) inherent process equipment contained entirely within the flue ductwork, (b) use a passive method of particulate matter separation from the flue gas stream, (c) recover unburned carbon and ash from the flue gas system, and (d) have no moving parts, no control inputs, nor any

## STATEMENT OF BASIS

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controllable parameters. CAM does not apply to the Unit 3 combined cycle units since these emissions units have nitrogen oxides (NO<sub>x</sub>) continuous emissions monitoring systems (CEMS) which are used to demonstrate continuous compliance.

### PROJECT REVIEW

Some changes were made to the facility's current Title V air operation permit. These included: reformatting, replacement of TV-6 with new Appendix TV and streamlining of emissions unit sections by moving common conditions to the new appendices, and the incorporation of specific conditions of air construction permit modification 0810010-013-AC dealing with excess emissions for the combined cycle turbine system.

### CONCLUSION

This project renews Title V air operation permit No. 0810010-009-AV, which was issued on January 1, 2004. This Title V air operation permit renewal is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-213, F.A.C. In accordance with the terms and conditions of this permit, the above named permittee is hereby authorized to operate the facility as shown on the application and approved drawings, plans, and other documents, on file with the permitting authority.

**Florida Power and Light Company  
Manatee Power Plant  
Facility ID No. 0810010  
Manatee County**

**Title V Air Operation Permit Renewal**

**Final Permit No. 0810010-014-AV**  
(Renewal of Title V Air Operation Permit No. 0810010-009-AV)

**Permitting Authority**

State of Florida  
Department of Environmental Protection  
Division of Air Resource Management  
Bureau of Air Regulation  
Title V Permitting Section

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

Telephone: 850/488-0114  
Fax: 850/921-9533

**Compliance Authority**

State of Florida  
Department of Environmental Protection  
Southwest District Office

13051 North Telecom Parkway  
Temple Terrace, Florida 33637-0926

Telephone: 813/632-7600  
Fax: 813/744-6084

# Title V Air Operation Permit Renewal

Permit No. 0810010-014-AV

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# Florida Department of Environmental Protection

Bob Martinez Center  
2600 Blair Stone Road  
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Charlie Crist  
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Jeff Kottkamp  
Lt. Governor

Michael W. Sole  
Secretary

**PERMITTEE:**

Florida Power and Light Company  
19050 State Road 62  
Parrish, Florida 34219-9220

Permit No. 0810010-014-AV  
Manatee Power Plant  
Facility ID No. 0810010  
Title V Air Operation Permit Renewal

The purpose of this permit is to renew the Title V air operation permit for the above referenced facility. The existing Manatee Power Plant is located at 19050 State Road 62, Parrish, in Manatee County. Universal Transverse Mercator (UTM) coordinates are: Zone 17, 367.250 km East and 3054.150 km North. Latitude is: 27° 36' 21" North; and, Longitude is: 82° 20' 44" West.

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

Effective Date: January 1, 2009  
Renewal Application Due Date: May 20, 2013  
Expiration Date: December 31, 2013

Joseph Kahn, Director  
Division of Air Resource Management

JK/tlv/jkh/tbc



## SECTION I. FACILITY INFORMATION.

### **Subsection A. Facility Description.**

This nominal 2,750 megawatt (MW) facility consists of two fossil fuel steam generators, a “4-on-1” gas-fired combined cycle unit and associated support equipment.

Fossil Fuel Steam Generators, Unit 1 and Unit 2: Each unit is a Foster-Wheeler Steam Generator rated at 800 MW (900 MW gross capacity) output. These units burn a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from Florida Power and Light Company (FPL) operations, discharging pollutants through a stack 499 feet above ground level. Each unit is equipped with multiple cyclones, a flue gas recirculation system and staged combustion and also operates a Westinghouse tandem compound, reheat-type extraction turbine.

Combined Cycle Gas Turbine, Unit 3: This unit consists of four (“4-on-1”) nominal 170 MW General Electric Model PG7241(FA) gas-fired turbine-electrical generator sets with evaporative inlet cooling systems, an automated gas turbine control system, an inlet air filtration system, four 495 million British thermal units per hour (MMBtu/hr) supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors, a single nominal 470 MW steam-electrical generator that serves all four gas turbine/HRSG systems, four 120 feet exhaust stacks, and associated support equipment. The total generating capacity of the “4-on-1” combined cycle system Unit 3 is 1150 MW.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities (See Appendix I and Appendix U).

### **Subsection B. Summary of Emissions Units.**

<b>EU No.</b>	<b>Brief Description</b>
<i>Regulated Emissions Units</i>	
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
005	Unit No.3A Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
006	Unit No.3B Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
007	Unit No.3C Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
008	Unit No.3D Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
<i>Unregulated Emissions Units and Activities</i>	
003	Emergency Diesel Generator, Miscellaneous Mobile Equipment and Internal Combustion Engines
004	Painting of Plant Equipment and Non Halogenated Solvent Cleaning Operations
010	Ammonia Storage Tank
011	Black Start Diesel Engines (3)

## SECTION I. FACILITY INFORMATION.

### **Subsection C. Applicable Regulations.**

Based on the Title V air operation permit renewal application received July 3, 2008, this facility is a major source of hazardous air pollutants (HAP). This facility is classified as a prevention of significant deterioration (PSD) major facility. A summary of applicable regulations is shown in the following table.

Regulation	EU No(s).
40 CFR 60, Subpart A, NSPS General Provisions	005, 006, 007, 008
40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978	
40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	
40 CFR 75 Acid Rain Monitoring Provisions	001, 002, 005, 006, 007, 008
State Rule Citations	
Rule 62-4, Florida Administrative Code (F.A.C.) (Permitting Requirements)	001, 002, 005, 006, 007, 008
Rule 62-204, F.A.C. (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference)	
Rule 62-210, F.A.C. (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms)	
Rule 62-212, F.A.C. (Preconstruction Review, PSD Review and Best Available Control Technology (BACT))	
Rule 62-213, F.A.C. (Title V Air Operation Permits for Major Sources of Air Pollution)	
Rule 62-214, F.A.C. (Requirements For Sources Subject To The Federal Acid Rain Program)	
Rule 62-296, F.A.C. (Emission Limiting Standards)	
Rule 62-297, F.A.C. (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures)	

## SECTION II. FACILITY-WIDE CONDITIONS.

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

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

### **Emissions and Controls**

**FW2. Objectionable Odor Prohibited.** No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

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

**FW4. General Visible Emissions.** No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

**FW5. Unconfined Particulate Matter.** Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- a. The facility shall construct temporary sandblasting enclosures when necessary, in order to perform sandblasting on fixed plant equipment.
- b. Maintenance of paved areas as needed.
- c. Regular mowing of grass and care of vegetation.
- d. Limiting access to plant property by unnecessary vehicles.
- e. Bagged chemical products are stored in concrete block buildings until they are used.
- f. Spills of powdered chemical products are cleaned up as soon as practicable.

[Rule 62-296.320(4)(c)2., F.A.C.; and provided by the 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<sup>st</sup> for 2009 and April 1<sup>st</sup> 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 by March 1<sup>st</sup> 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.]

## SECTION II. FACILITY-WIDE CONDITIONS.

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

- a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. 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.
- b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.

[40 CFR 68]

**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 vacature 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.]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

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

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

Fossil fuel fired steam generators Unit 1 and Unit 2 are each nominal 800 megawatt (900 MW gross capacity) (electric) steam generators designated as Manatee Plant Unit 1 and Unit 2. The emissions units are fired on a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from FPL operations. Propane is utilized primarily for ignition of the main fuel. When firing fuel oil (or combinations of authorized fuels), the maximum heat input for each boiler is 8,650 mmBtu per hour. When firing natural gas alone, the maximum heat input for each boiler is 5,670 mmBtu per hour.

Each emissions unit consists of a boiler which drives a turbine generator. Emissions are controlled with multiple cyclones, a flue gas recirculation system and staged combustion. The twin register low nitrogen oxides (NO<sub>x</sub>) burners (ABB Combustion Services, Ltd.) are dual fuel with mechanical atomization for oil firing. Each unit is equipped with a 499 foot stack height. The stack for Unit 1 has a 27.3 foot exit diameter; the stack for Unit 2 has a 26.2 foot exit diameter. Flow rate is 2,739,143 actual cubic feet per second (acfm), exit velocity is 78 feet per second (fps), exit temperature is 344 °F for Unit 1; flow rate is 2,667,410 acfm, exit velocity is 82.5 fps, exit temperature is 325 °F for Unit 2.

The mechanical dust collectors of Units 1 and 2 are excluded from compliance assurance monitoring (CAM), because they are (a) inherent process equipment contained entirely within the flue ductwork, (b) use a passive method of particulate matter separation from the flue gas stream, (c) recover unburned carbon and ash from the flue gas system, and (d) have no moving parts, no control inputs, nor any controllable parameters.

*{Permitting notes: These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1976 and fossil fuel fired steam generator Unit 2 began commercial operation in 1977. These emissions units may inject additives such as magnesium oxide, magnesium hydroxide and related compounds into each boiler.}*

#### **Essential Potential to Emit (PTE) Parameters**

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	8,650	No. 2 or 6 Fuel Oil (Alone or w/Natural Gas)
	5,670	Natural Gas (Alone)
002	8,650	No. 2 or 6 Fuel Oil (Alone or w/Natural Gas)
	5,670	Natural Gas (Alone)

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-296.405, F.A.C.; and Permit No. 0810010-007-AC]

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

**A.3. Methods of Operation - Fuels.**

- Startup.** The only fuels allowed to be burned are any combination of natural gas, No. 6 fuel oil, No. 2 fuel oil and propane.
- Normal.** The only fuels allowed to be burned are any combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane and on-specification used oil from Florida Power and Light Company (FPL) operations.

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

When available, the Department strongly encourages the permittee to fire natural gas as a clean-burning alternative to fuel oil. [Rule 62-213.410, F.A.C.; Permit No. 0810010-007-AC]

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

#### **Emission Limitations and Standards**

*{Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}*

Unless otherwise specified, the averaging times for Specific Conditions **A.5.-A.10.** are based on the specified averaging time of the applicable test method.

- A.5. Visible Emissions.** Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall compliance test for particulate matter emissions annually. [Rule 62-296.405(1)(a), F.A.C.; and OGC Case Nos. 83-0580 & 83-0581, Order dated April 24, 1984.]

- 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.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

[Rule 62-210.700(3), F.A.C. Note: these units have operational continuous opacity monitors.]

- A.7. Particulate Matter.** Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1)(b), F.A.C.]

- 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.]

- A.9. Sulfur Dioxide.** The sulfur content of fuel oils burned shall not exceed 1.0 percent by weight, as received at the plant. The blending of natural gas shall not be used to demonstrate compliance with the sulfur dioxide standard for "liquid fuel" in Rule 62-296.405(c), F.A.C. [Rules 62-213.440 and 62-296.405(1)(c)1.g., F.A.C., applicant agreement with EPA on March 3, 1998, and Permit No. 0810010-007-AC]

*{Permitting Note from 0810010-007-AC: The maximum fuel sulfur content of pipeline natural gas is 10 grains of sulfur per 100 standard cubic feet of natural gas. However, pipeline natural gas typically contains less than 1 grain of sulfur per 100 SCF of natural gas.}*

- A.10. Nitrogen Oxides.** Nitrogen oxides emissions shall not exceed 0.30 pounds per million Btu heat input. Compliance shall be demonstrated based on a 30-day rolling average as measured by a continuous emission monitoring system (CEMS). The CEMS must meet the performance specifications contained in 40 CFR 75. [Rule 62-296.405, F.A.C.; AO 41-204804 and AO 41-219341, issued August 30, 1993]

#### **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.11. Malfunction.** Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

- A.12. Startup or Shutdown.** Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]
- A.13. Prohibition.** 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.]

#### **Continuous Monitoring Requirements**

- A.14. COMS for Periodic Monitoring.** The owner or operator was required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring. [Rule 62-213.440, F.A.C., and applicant agreement with EPA on March 3, 1998]

#### **Test Methods and Procedures**

*{Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}*

- A.15. Test Methods.** Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5B	Method for Determining Particulate Matter Emissions (All PM is assumed to be PM <sub>10</sub> .)
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-296.405, F.A.C.]

- A.16. Visible Emissions.** 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. [Rule 62-296.405, F.A.C.]
- A.17. Operating Conditions During Testing - PM and VE.** When required, testing for particulate matter and visible emissions shall be conducted while firing No. 6 fuel oil at the maximum allowable rate of 8650 million Btu per hour, except as provided below. Particulate matter and visible emissions shall be conducted under both sootblowing and non-sootblowing conditions, and shall be conducted while injecting additives consistent with normal operating practices. Testing may be conducted while firing No. 6 fuel oil at less than 90 percent of the maximum allowable rate; however, subsequent emissions unit operation is limited as described in Appendix TR of this permit. [Rules 62-4.070(3) and 62-213.440 F.A.C.; AO 41-204804 Specific Condition 5 and AO 41-219341, Specific Condition 5]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

- A.18. Annual Compliance Tests.** During each federal fiscal year (October 1<sup>st</sup> to September 30<sup>th</sup>), each EU shall be tested to demonstrate compliance with the emissions standards for VE and PM. Annual compliance tests for these pollutants shall be performed on each unit for each fuel fired for 400 hours or more during the federal fiscal year. Unless specifically requested by the Compliance Authority pursuant to Rule 62-297.310(7)(b), F.A.C., periodic opacity tests are not required when firing natural gas. [Rule 62-297.310(7), F.A.C.]
- A.19. Annual Tests Required.** Except as provided in Specific Conditions A.21 and A.22 of this permit, emission testing for particulate emissions and visible emissions shall be performed annually, each federal fiscal year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service. [Rules 62-4.070(3) and 62-213.440, F.A.C.]
- A.20. Sulfur Dioxide.** **The permittee elected to demonstrate compliance using fuel sampling and analysis.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. [Rule 62-296.405, F.A.C.]
- A.21. When VE Tests Not Required.** By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
- only gaseous fuel(s); or
  - gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
  - only liquid fuel(s) for less than 400 hours per year.
- [Rule 62-297.310(7)(a)4., F.A.C.]
- A.22. When PM Tests Not Required.** Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
- only gaseous fuel(s); or
  - gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
  - only liquid fuel(s) for less than 400 hours per year.
- [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and ASP Number 97-B-01.]
- A.23. DEP Method 9.** The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
- 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.
  - 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:
    - 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.
    - 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.]



### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

- A.24. Particulate Matter.** 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 a filter temperature of 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 or 3A with Orsat analysis 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. [Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]
- A.25. 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. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance using fuel sampling and analysis.** [Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.]
- A.26. Alternate Sampling Procedure.** The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard:
- Compliance with the liquid fuel sulfur limit shall be verified by a fuel analysis provided by the vendor or performed by FPL upon each fuel delivery at the Port Manatee Fuel Oil Terminal with the following exception: in cases where No. 6 fuel oil is received with a sulfur content exceeding 1.0 percent by weight, and blending at the terminal is required to obtain a fuel mix equal to the applicable percent sulfur limit, an analysis of a fuel sample representative of fuel from the fuel storage tanks shall be performed by FPL prior to transferring oil to the Manatee plant. Reports of percent sulfur content of these analyses shall be maintained at the power plant facility.
  - The owner or operator shall maintain records of the as-fired fuel oil heating value, density or specific gravity, and the percent sulfur content. Fuel sulfur content, percent by weight, for liquid fuels shall be determined by either ASTM D2622-94, ASTM D4294-90 (95), ASTM D1552-95, ASTM D1266-91, or both ASTM D4057-88 and ASTM D129-95 (or latest editions) to analyze a representative sample of the fuel oil.
- [Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; Applicant agreement with EPA on March 3, 1998.]
- A.27. Testing While Injecting Additives.** The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices. [Rule 62-213.440, F.A.C.; applicant agreement with EPA on March 3, 1998]
- A.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(7), F.A.C.]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

##### **Recordkeeping and Reporting Requirements**

{Permitting Note: See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.}

**A.29. Reporting Schedule.** The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Fuel Analysis Report	Monthly.	A.30.
Excess Emissions - Malfunctions	Quarterly (if requested).	A.32.

**A.30. Fuel Analysis Report.** The owner or operator shall, by the fifteenth day following each calendar month, submit to the Department's Southwest District, Air Section, a report of fuel analyses that are representative of each fuel received in the preceding month. The report shall document the heating value, density or specific gravity, and the percent sulfur content by weight of each fuel fired. [Rule 62-4.070(3) and 62-213.440, F.A.C.; AO 41-204804 Specific Condition 6 and AO 41-219341 Specific Condition 6]

**A.31. Excess Emissions - Reports.** Submit to the Department's Southwest District, Air Section, a written report of emissions in excess of emission limiting standards for opacity and sulfur dioxide as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

**A.32. Excess Emissions - Malfunctions.** In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District, Air Section, 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's Southwest District, Air Section. [Rule 62-210.700(6), F.A.C.]

##### **Other Requirements**

**A.33. Used Oil.** Burning of on-specification used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:

- On-specification Used Oil Allowed as Fuel.** This permit allows the burning of used oil fuel meeting EPA "on-specification" used oil specifications, with a polychlorinated biphenyls (PCB) concentration of less than 50 parts per million (ppm), originating from FPL operations. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility. On-specification used oil shall meet the following specifications:
  - (1) Arsenic shall not exceed 5.0 ppm;
  - (2) Cadmium shall not exceed 2.0 ppm;
  - (3) Chromium shall not exceed 10.0 ppm;
  - (4) Lead shall not exceed 100.0 ppm;
  - (5) Total halogens shall not exceed 1000 ppm;
  - (6) Flash point shall not be less than 100 degrees F.[40 CFR 279, Subpart B.]
- Quantity Limited.** The maximum total quantity of used oil that may be burned in both emissions units is 40,000 gallons in any consecutive 12-month period.
- Used Oil Containing PCBs Not Allowed.** Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.
- PCB Concentration of 2 to less than 50 ppm.** On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection A. Emissions Units 001 and 002

with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

- e. *Testing Required:* The owner or operator shall sample and analyze each batch of used oil to be burned for arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs. Additionally:
    - (1) Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.
    - (2) Split samples of the used oil shall be retained for three months after analysis for further testing if necessary.

[AO 41-204804 Specific Condition 9 and AO 41-219341 Specific Condition 9]
  - f. *Record Keeping Required.* The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
    - (1) The gallons of on-specification used oil received and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
    - (2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
    - (3) Results of the analyses required above.

[40 CFR 279.61 and 761.20(e)]
  - g. *Reporting Required.* The owner or operator shall submit to the Department's Southwest District, Air Section, within thirty days of the end of each calendar month in which used oil is burned, the analytical results and the total amount of on-specification used oil burned during the previous calendar month. The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.
- [Rules 62-4.070(3) and 62-213.440, F.A.C.; 40 CFR 279 and 40 CFR 761, unless otherwise noted]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

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

EU No.	Brief Description
005	Unit 3A Gas Turbine (170 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)
006	Unit 3B Gas Turbine (170 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)
007	Unit 3C Gas Turbine (170 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)
008	Unit 3D Gas Turbine (170 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)

Each unit consists of a nominal 170 MW General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a heat recovery steam generator (HRSG) each equipped with a 495 MMBtu/hr natural gas fired duct burner, a stack, and associated support equipment. Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit system is 1,150 MW. Each stack is 120 ft tall (19 ft diameter). At a compressor inlet air temperature of 59° F, each gas turbine heat input is approximately 1600 MMBtu lower heating value (LHV) per hour. The exhaust flow rate is 1,004,200 actual cubic feet per minute (acfm) at a temperature of 202° F.

The units are fired exclusively with natural gas. The efficient combustion of natural gas at high temperatures minimizes emissions of carbon monoxide (CO), particulate matter (PM/PM<sub>10</sub>), sulfuric acid mist (SAM), sulfur dioxide (SO<sub>2</sub>), and volatile organic compounds (VOC). Nitrogen oxides (NO<sub>x</sub>) emissions are reduced by Dry Low-NO<sub>x</sub> (DLN) combustion technology (simple cycle mode). A selective catalytic reduction (SCR) system combined with Dry Low-NO<sub>x</sub> (DLN) combustion technology further reduces NO<sub>x</sub> emissions during combined cycle mode. These emissions units commenced commercial operation in May 2005.

Each gas turbine is equipped with a continuous emissions monitoring system (CEMS) to measure and record CO and NO<sub>x</sub> emissions, as well as flue gas oxygen or carbon dioxide content.

Compliance assurance monitoring (CAM) does not apply since these emissions units have NO<sub>x</sub> CEMS which are used to demonstrate continuous compliance.

*{Permitting note: These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines; 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(8), F.A.C.; Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permit PSD-FL-328 (0810010-006-AC) issued 04/15/03.}*

Note: On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines built after January 14, 2003. Unit 3 was under contractual obligations before this date and is therefore an existing unit. Currently, 'existing combustion turbines' are not required to meet the emission limitations, notifications, reporting or any other requirements of Subpart YYYY. EPA may at a future date promulgate standards for existing units.

#### **Applicable Standards and Regulations**

**B.1. NSPS Subpart GG Requirements.** The Department determined that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Gas Turbines in 40 CFR 60, Subpart GG. For completeness, the applicable Subpart GG requirements are included in Appendix NSPS Subpart GG of this permit. [Rule 62-204.800, F.A.C.]

**B.2. NSPS Subpart Da Requirements.** Each heat recovery steam generator equipped with a 495 mmBTU/hr natural gas fired duct burner (lower heating value) (LHV) shall comply with all applicable provisions of 40

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

CFR 60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800, F.A.C. The codification of 40 CFR 60, Subpart Da promulgated on September 3, 1998 also applies to this project. The Department determined that compliance with the BACT emissions performance and monitoring requirements also assures compliance with this NSPS. For completeness, the applicable requirements of Subpart Da are included in Appendix Da. [Rule 62-204.800, F.A.C.]

- B.3. Gas Turbine Units 3A throughout 3D.** The permittee is authorized to operate, tune and maintain the four combustion turbines. Each gas turbine includes the Speedtronic<sup>TM</sup> automated gas turbine control system. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air cooling system. The gas turbines utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Hot water/electric heaters preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers preheat the natural gas. [PSD-FL-328 (0810010-006-AC)]
- B.4. Gas Turbine Controls.**
- DLN Combustion Technology.** The permittee is authorized to operate, tune and maintain the General Electric Company DLN-2.6 combustion system to control NO<sub>x</sub> emissions from each turbine. The DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted level for CO and NO<sub>x</sub>. Each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
  - Selective Catalytic Reduction (SCR) System.** The permittee is authorized to operate, tune and maintain a SCR system to control NO<sub>x</sub> emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be operated to achieve the permitted levels for NO<sub>x</sub> emissions and ammonia slip.

[Design; Rule 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]

*{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions of 40 CFR 68.}*

- B.5. Heat Recovery Steam Generators.** The permittee is authorized to operate and maintain the four heat recovery steam generators (HRSG). Each HRSG is designed to recover heat energy from one of the four gas turbines (3A-3D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG is equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). [PSD-FL-328 (0810010-006-AC)]

*{Permitting Note: The four HRSG units deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}*

#### **Essential Potential to Emit (PTE) Parameters**

- B.6. Gas Turbine Permitted Capacity.** The maximum heat input rate to each gas turbine is 1,600 MMBtu/hr (normal conditions) based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.; PSD-FL-328 (0810010-006-AC)]
- B.7. HRSG Duct Burner Permitted Capacity.** The total maximum heat input rate to the duct burners for each HRSG is 495 MMBTU/hr based on the lower heating value (LHV) of the natural gas. [Rule 62-210.200(PTE), F.A.C.; PSD-FL-328 (0810010-006-AC)]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

- B.8. 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.9. Methods of Operation.** Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
- Hours of Operation.** Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
  - Authorized Fuels.** Each gas turbine shall fire natural gas as the primary fuel, which shall contain on average no more than 2 grains of sulfur per 100 standard cubic feet of natural gas.
  - Combined Cycle Operation.** Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
  - Combined Cycle Operation with HRSG Duct Firing.** When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input to the duct burners (all four HRSG units) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.
  - Simple Cycle Operation.** Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.
    - Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.
    - After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per unit during any consecutive 12 months.
  - Inlet Fogging:** In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.
  - Power Augmentation (PA):** When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Each gas turbine shall operate in this power augmentation mode no more than 400 hours per unit during any consecutive 12 months.
  - Peaking:** When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate in this peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

[Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]

#### **Emission Limitations and Standards**

*{Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}*

- B.10. BACT Standards.** Emissions from each gas turbine shall not exceed the following standards.

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O <sub>2</sub>	lb/hour	ppmvd @ 15% O <sub>2</sub>
CO <sup>a</sup>	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal Operation	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	10.0, 24-hr
NO <sub>x</sub> <sup>b</sup>	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	2.5, 24-hr
		Combined Cycle w/SCR, All Modes	N/A	N/A	2.5, 24-hr
PM/PM <sub>10</sub> <sup>c</sup>	Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO <sub>2</sub> <sup>d</sup>	Gas	Simple or Combined Cycle	Fuel Specifications		
VOC <sup>e</sup>	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
VOC <sup>e</sup>	Gas	Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia <sup>f</sup>	Gas	Combined Cycle w/SCR	5	NA	NA

Notes:

- a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hr CO CEMS standard shall be determined separately for each mode of operation based on the hours of operation in each mode.

*{Permitting Note: 24-hr compliance average may be based on as little as 1-hr of data or as much as 24-hr of CEMS data.}*

- b. Compliance with the NO<sub>x</sub> standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NO<sub>x</sub> mass emission rates are defined as oxides of nitrogen expressed as NO<sub>2</sub>. Compliance with the 24-hr NO<sub>x</sub> CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method.

*{Permitting Note: A 24-hr compliance average may be based on as little as 1-hr of CEMS data or as much as 24-hr of CEMS data.}*

- c. The fuel specifications established in this subsection combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

for PM/PM<sub>10</sub> emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

*{Permitting Note: PM<sub>10</sub> emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning.}*

- d. The fuel sulfur specifications in this subsection effectively limit the potential emissions of SAM and SO<sub>2</sub> from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Specific Condition No. B.30 of this subsection.

*{Permitting Note: SO<sub>2</sub> emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SAM emissions are estimated to be less than 10% of the SO<sub>2</sub> emissions.}*

- e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
- f. Subject to the requirements of this subsection, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

*{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}*

[Rule 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]

- B.11. Duct Burners.** The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. [PSD-FL-328 (0810010-006-AC)]

*{Permitting Note: During duct firing, compliance with the limits of this permit also demonstrates compliance with the standards of NSPS 40 CFR 60, Subpart Da for duct burners.}*

- B.12. Combined Cycle Operation With Steam Dumped to Condenser.** If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR). [PSD-FL-328 (0810010-006-AC)]

#### **Excess Emissions**

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

- B.13. Operating Procedures.** The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSG units, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]

- B.14. 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,



### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

**B.15. Alternate Visible Emissions Standard.** Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

**B.16. Excess Emissions Allowed.** As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A “documented malfunction” means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period (or shall not exceed eight hours per 4-unit site, with the additional provision of a limit of 2 startup periods per 24 hours per unit) except for the following specific cases.

a. *Steam Turbine/HRSG System Cold Startup.* For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed eight (8) hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold “startup of the steam turbine system” is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

*{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

b. *Shutdown.* For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period.

c. *Gas Turbine/HRSG System Cold Startup.* For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four (4) hours in any 24-hour period. “Cold startup of a gas turbine/HRSG system” is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Rules 62-212.400(BACT) and 62-210.700, F.A.C.; PSD-FL-328 (0810010-006-AC); 0810010-013-AC]

**B.17. Work Practice Standard and Load Restriction.**

a. *Simple Cycle Work Practice BACT.* Each unit will be operated according to manufacturer specifications and control systems. The CT control system is designed to reach Mode 5Q (i.e., five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

b. *Combined Cycle Work Practice BACT.* A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following determination of initial compliance with emission limits when operating in combined cycle mode.

c. *Low-Load Restriction.* Except for startup and shutdown, malfunctions, commissioning and recommissioning, operation at loads where the DLN 2.6 system is not in pre-mix mode is prohibited.

[PSD-FL-328 (0810010-006-AC)]

**B.18. DLN Tuning.** CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer’s specifications. A “major tuning session” would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

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to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Rule 62-4.070(3), F.A.C.; PSD-FL-328 (0810010-006-AC)]

#### **Monitoring of Operations**

**B.19. Ammonia Monitoring Requirements.** In accordance with the manufacturer's specifications, the permittee shall calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO<sub>x</sub> emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO<sub>x</sub> monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]

#### **Continuous Monitoring Requirements**

**B.20. CEM Systems.** The permittee shall calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO<sub>x</sub> from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO<sub>x</sub> standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

- a. *CO Monitors.* Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
- b. *NO<sub>x</sub> Monitors.* Each NO<sub>x</sub> monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR Part 75. The RATA tests required for the NO<sub>x</sub> monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO<sub>x</sub> monitor span values shall be set approximately considering the allowable method of operation and corresponding emission standards.
- c. *Diluent Monitors.* The oxygen (O<sub>2</sub>) content or carbon dioxide (CO<sub>2</sub>) content of the flue gas shall also be monitored at the location where CO and NO<sub>x</sub> are monitored to correct the measured emissions rates to 15% oxygen. If a CO<sub>2</sub> monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR Part 75.
- d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd, corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO<sub>x</sub> as specified in this permit. For purpose of determining compliance with the CEMS emission standard of this permit, missing (or excluded) data shall not be submitted. Upon request by the Department, the CEMS emission rates shall be corrected to International Organization for Standardization (ISO) conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

- e. *24-hour Block Averages.* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]
- f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, malfunction, and DLN tuning. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Specific Condition No. 16 and 19 of this subsection. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department.

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]

*{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}*

#### **Test Methods and Procedures**

*{Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}*

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source <i>{Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}</i>

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources <i>{Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}</i>
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography <i>{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}</i>
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at: [www.epa.gov/ttn/emc/ctm.html](http://www.epa.gov/ttn/emc/ctm.html). No other methods may be used for compliance testing unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A; PSD-FL-328 (0810010-006-AC)]

**B.22. Special Compliance Determinations.** The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. Each gas turbine shall be stack tested to demonstrate compliance with the emission standards for CO, NO<sub>x</sub>, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in this permit. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NO<sub>x</sub> standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NO<sub>x</sub> mass emissions standards. CO and NO<sub>x</sub> emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the test requirement for similar operation in combined cycle mode. [Rule 62-297.310(7)(a)1., F.A.C.; PSD-FL-328 (0810010-006-AC)]

**B.23. Continuous Compliance.** The permittee shall demonstrate continuous compliance with the CO and NO<sub>x</sub> emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

**B.24. Annual Compliance Tests.** During each federal fiscal year (October 1<sup>st</sup> to September 30<sup>th</sup>), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NO<sub>x</sub> emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

#### Subsection B. Emissions Units 005, 006, 007 and 008

*{Permitting Note: After initial compliance with the VOC standards are demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}*

- B.25. Additional Ammonia Slip Testing.** If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:
- Begin testing and reporting the ammonia slip for each subsequent calendar quarter;
  - Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and
  - Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

- B.26. 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(7), F.A.C.]

#### **Recordkeeping and Reporting Requirements**

*{Permitting Note: See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.}*

- B.27. Reporting Schedule.** The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Operations Summary	Monthly.	B.29.
Excess Emissions	Quarterly.	B.32.

- B.28. Monitoring of Capacity.** The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; PSD-FL-328 (0810010-006-AC)]
- B.29. Monthly Operations Summary.** By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
- B.30. Fuel Sulfur Records.** The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

### SECTION III. EMISSIONS UNITS AND SPECIFIC CONDITIONS.

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#### Subsection B. Emissions Units 005, 006, 007 and 008

- B.31. Malfunction Notification.** Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports of the malfunctions. [Rule 62-210.700(6), F.A.C.; PSD-FL-328 (0810010-006-AC)]
- B.32. Quarterly Excess Emission Report.** Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions. The information shall be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

## SECTION IV. ACID RAIN PART

### Subsection A. Acid Rain Phase II

Operated by: Florida Power and Light Company  
ORIS Code: 6042

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

<b><u>E.U. ID No.</u></b>	<b><u>Brief Description</u></b>
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
005	Unit No.3A Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
006	Unit No.3B Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
007	Unit No.3C Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator
008	Unit No.3D Gas Turbine (nominal 170 MW) with Heat Recovery Steam Generator

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

- a. DEP Form No. 62-210.900(1)(a), dated 04/15/08, received 07/03/08.  
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

**A.2.** Sulfur dioxide (SO<sub>2</sub>) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2009	2010	2011	2012	2013
001	PMT1	SO <sub>2</sub> allowances, under Table 2 of 40 CFR 73	13,773*	13,799*	13,799*	13,799*	13,799*
002	PMT2	SO <sub>2</sub> allowances, under Table 2 of 40 CFR 73	12,697*	12,716*	12,716*	12,716*	12,716*
005	MTCT3A	SO <sub>2</sub> allowances to be determined by USEPA	0*	0*	0*	0*	0*
006	MTCT3B	SO <sub>2</sub> allowances to be determined by USEPA	0*	0*	0*	0*	0*
007	MTCT3C	SO <sub>2</sub> allowances to be determined by USEPA	0*	0*	0*	0*	0*
008	MTCT3D	SO <sub>2</sub> allowances to be determined by USEPA	0*	0*	0*	0*	0*

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

## SECTION IV. ACID RAIN PART

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### Subsection A. Acid Rain Phase II

- 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.  
[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]
- A.4.** Comments, notes, and justifications: None.



## SECTION IV. ACID RAIN PART

### Subsection A. Acid Rain Phase II

Acid Rain Part- Page 1

## Acid Rain Part Application

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

This submission is: ☐ New ☒ Revised

#### STEP 1

Identify the source by plant name, State, and ORIS code

Plant Name: **Manatee**

State: **Florida**

ORIS Code: **6042**

#### STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a	b	c	d
Unit ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New Units Commence Operation Date	New Units Monitor Certification Deadline
MTCT3A	Yes	N/A	N/A
MTCT3A	Yes	N/A	N/A
MTCT3A	Yes	N/A	N/A
MTCT3A	Yes	N/A	N/A
PMT1	Yes	N/A	N/A
PMT2	Yes	N/A	N/A
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

DEP Form No. 62-210.900(1)(a) - Form  
Effective: 06/16/03

## SECTION IV. ACID RAIN PART

### Subsection A. Acid Rain Phase II

Acid Rain Part - Page 2

**Manatee**

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 Department 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 Department; 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.

##### 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 Department:
  - (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,

## SECTION IV. ACID RAIN PART

### Subsection A. Acid Rain Phase II

Acid Rain Part - Page 3

STEP 3,  
Cont'd.

**Manatee**

Plant Name (from Step 1)

#### 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<sub>x</sub> 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, 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 72.7 or 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

Read the  
certification  
statement, sign,  
and date

#### Certification

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

Name: **Sheila M. Wilkinson**

Signature



Date

4-15-08

## SECTION V. APPENDICES.

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Appendix A, Glossary.

Appendix ASP, ASP Number 97-B-01 (With Scrivener's Order Dated July 9, 1997).

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

Appendix NSPS, Subpart A – General Provisions.

Appendix NSPS, Subpart Da.

Appendix NSPS, Subpart GG.

Appendix O, Order Granting Reduced Sampling Frequency.

Appendix RR, Facility-wide Reporting Requirements.

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

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° 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<sup>2</sup>**: square feet  
**ft<sup>3</sup>**: 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

**APPENDIX A**

**ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION NUMBERS**

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**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<sub>x</sub>:** nitrogen oxides  
**NSPS:** New Source Performance Standards  
**O&M:** operation and maintenance  
**O<sub>2</sub>:** oxygen  
**ORIS:** Office of Regulatory Information Systems  
**OS:** Organic Solvent  
**Pb:** lead  
**PM:** particulate matter  
**PM<sub>10</sub>:** 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<sub>2</sub>:** sulfur dioxide  
**TPH:** tons per hour  
**lbs/hr:** pounds per hour  
**LONG:** Longitude  
**MACT:** maximum achievable technology  
**mm:** millimeter  
**MMBtu:** million British thermal units  
**MSDS:** material safety data sheets

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## APPENDIX A

### ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION NUMBERS

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**MW:** megawatt  
**NESHAP:** National Emissions Standards for Hazardous Air Pollutants  
**NO<sub>x</sub>:** nitrogen oxides  
**NSPS:** New Source Performance Standards  
**O&M:** operation and maintenance  
**O<sub>2</sub>:** oxygen  
**ORIS:** Office of Regulatory Information Systems  
**OS:** Organic Solvent  
**Pb:** lead  
**PM:** particulate matter  
**PM<sub>10</sub>:** 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<sub>2</sub>:** 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

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#### 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.*

## APPENDIX A

### ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION 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



APPENDIX ASP

Alternate Sampling Procedure: ASP Number 97-B-01

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

## Alternate Sampling Procedure: ASP Number 97-B-01

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

## Alternate Sampling Procedure: ASP Number 97-B-01

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;

## Alternate Sampling Procedure: ASP Number 97-B-01

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

## Alternate Sampling Procedure: ASP Number 97-B-01

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:

Alternate Sampling Procedure: ASP Number 97-B-01

- (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

## Alternate Sampling Procedure: ASP Number 97-B-01

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

## Alternate Sampling Procedure: ASP Number 97-B-01

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.

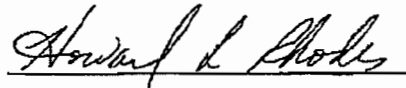
This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

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, 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 18<sup>th</sup> 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 Olden 3-18-97  
Clerk Date

APPENDIX ASP

Alternate Sampling Procedure: ASP Number 97-B-01

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, Director  
Division of Air Resources Management  
Twin Towers Office Building  
2600 Blair Stone Road  
Tallahassee, Florida 32399-2400  
(904) 488-0114

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**APPENDIX I**

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**LIST OF INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES**

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

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

	<b>Brief Description of Emissions Units and/or Activities</b>
1	Fire Protection Equipment
2	Mobile Emergency Diesel Generator
3	Fuel Gas System Miscellaneous Vents
4	Fuel Oil System Miscellaneous Vents
5	Gas Metering Area Miscellaneous Vents
6	Water Plant Analysis Room Exhaust Hood
7	Water Treatment Vents
8	Hazardous Waste Building Roof Vents
9	Fire Pump House Vent
10	Machine Shop Fans
11	Plant Service Building Roof Exhaust Fans
12	Waste Water Treatment Basins and Vents
13	Waste Water Treatment Control Building Roof Vents
14	Combustion Turbine and Accessories Vents
15	Steam Turbine System Vents
16	Circulating and Open Cooling Water System Vents
17	Bulk Gas Supply Vents
18	HRSG Feedwater and Steam, System Vents

### ***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***

#### ***§ 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.

**APPENDIX NSPS SUBPART A**  
**SUBPART A-GENERAL PROVISIONS FOR 40 CFR 60**

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*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.

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*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<sub>x</sub> 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.

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*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<sup>3</sup>—cubic meter  
mg—milligram—10<sup>-3</sup> gram  
mm—millimeter—10<sup>-3</sup> meter  
Mg—megagram—10<sup>6</sup> gram  
mol—mole  
N—newton  
ng—nanogram—10<sup>-9</sup> gram  
nm—nanometer—10<sup>-9</sup> meter  
Pa—pascal  
s—second  
V—volt  
W—watt  
Ω—ohm  
μg—microgram—10<sup>-6</sup> 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

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**SUBPART A-GENERAL PROVISIONS FOR 40 CFR 60**

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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<sub>2</sub>—carbon dioxide  
HCl—hydrochloric acid



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Hg—mercury  
H<sub>2</sub>O—water  
H<sub>2</sub>S—hydrogen sulfide  
H<sub>2</sub>SO<sub>4</sub>—sulfuric acid  
N<sub>2</sub>—nitrogen  
NO—nitric oxide  
NO<sub>2</sub>—nitrogen dioxide  
NO<sub>x</sub>—nitrogen oxides  
O<sub>2</sub>—oxygen  
SO<sub>2</sub>—sulfur dioxide  
SO<sub>3</sub>—sulfur trioxide  
SO<sub>x</sub>—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.**

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**SUBPART A-GENERAL PROVISIONS FOR 40 CFR 60**

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- (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.

**APPENDIX NSPS SUBPART A**  
**SUBPART A-GENERAL PROVISIONS FOR 40 CFR 60**

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- (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.

**APPENDIX NSPS SUBPART A**  
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Figure 1—Summary Report—Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO<sub>2</sub>/NO<sub>x</sub>/TRS/H<sub>2</sub>S/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<sup>1</sup> \_\_\_\_\_

Emission data summary <sup>1</sup>		CMS performance summary <sup>1</sup>	
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]	% <sup>2</sup>	3. [Total CMS Downtime] × (100) [Total source operating time]	% <sup>2</sup>

<sup>1</sup>For opacity, record all times in minutes. For gases, record all times in hours.

<sup>2</sup>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

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(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

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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

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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

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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 determining 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.



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- (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:

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- (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.

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- (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<sub>2</sub> or 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

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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:

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- (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.

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[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.**



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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](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)<sup>e1</sup>, 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).



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- (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).

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- (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 (Diocetyl 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).

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- (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.

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- (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).

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- (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. O57007. 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,

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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:

$$V_{\max} = (X_{H_2} - K_1) * K_2$$

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.

$X_{H_2}$  = 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.

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- (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:

$$H_T = K \cdot \sum_{i=1}^n C_i H_i$$

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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;

$$K = \frac{\text{Constant}}{1.740 \times 10^{-7}} \left( \frac{1}{\text{ppm}} \right) \left( \frac{\text{g mole}}{\text{scm}} \right) \left( \frac{\text{MJ}}{\text{kcal}} \right)$$

where the standard temperature for  $\left( \frac{\text{g mole}}{\text{scm}} \right)$  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.

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- (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



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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]

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**SUBPART Da- STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978**

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***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.

***§ 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:

**SUBPART Da- STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978**

- (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<sub>2</sub>) 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.

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**APPENDIX NSPS SUBPART Da**

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**SUBPART Da- STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978**

*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.

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*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<sub>2</sub>) is determined under §60.50Da(c).
- (3) For nitrogen oxides (NO<sub>x</sub>) 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.

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*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<sub>2</sub> 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<sub>2</sub> 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.

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- (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<sub>2</sub>).**

- (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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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:

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- (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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> emission limit (ng/J heat input);

$\%P_s$  = Percentage of potential SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> in excess of either:



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- (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 cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>x</sub>).**

- (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<sub>x</sub> (expressed as NO<sub>2</sub>) 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<sub>x</sub> emission limits.

Fuel type	Emission limit for heat input
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	ng/J	lb/MMBtu
<b>Gaseous fuels:</b>		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
<b>Liquid fuels:</b>		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
<b>Solid fuels:</b>		
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 <sup>2</sup>	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit <sup>2</sup>	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

<sup>1</sup>Exempt from NO<sub>x</sub> standards and NO<sub>x</sub> monitoring requirements.

<sup>2</sup>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<sub>x</sub> 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:

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$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

- $E_n$  = Applicable standard for  $\text{NO}_x$  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  $\text{NO}_x$  (expressed as  $\text{NO}_2$ ) 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  $\text{NO}_x$  (expressed as  $\text{NO}_2$ ) 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  $\text{NO}_x$  (expressed as  $\text{NO}_2$ ) 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  $\text{NO}_x$  (expressed as  $\text{NO}_2$ ) 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  $\text{NO}_x$  (expressed as  $\text{NO}_2$ ) 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  $\text{NO}_x$  (expressed as  $\text{NO}_2$ ) 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.

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- (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<sub>x</sub> (expressed as NO<sub>2</sub>) 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<sub>x</sub> (expressed as NO<sub>2</sub>) 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<sub>x</sub> (expressed as NO<sub>2</sub>) 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  $20 \times 10^{-6}$  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  $66 \times 10^{-6}$  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  $97 \times 10^{-6}$  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  $175 \times 10^{-6}$  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  $16 \times 10^{-6}$  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,

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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.

$$EL_b = \frac{\sum_{i=1}^n EL_i (HH_i)}{\sum_{i=1}^n HH_i} \quad (\text{Eq. 1})$$

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  $20 \times 10^{-6}$  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<sub>2</sub> emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO<sub>2</sub> 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<sub>2</sub> emission reduction

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requirements under §60.43Da(a) but must, as a minimum, reduce SO<sub>2</sub> 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<sub>x</sub> 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 <sub>2</sub>	6,000–10,000
Fluidized bed combustion (atmospheric)	SO <sub>2</sub>	400–3,000
Fluidized bed combustion (pressurized)	SO <sub>2</sub>	400–1,200
Coal liquification	NO <sub>x</sub>	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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> 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<sub>2</sub> 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,

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- (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<sub>2</sub> emission limitations and percentage reduction requirements under §60.43Da and the NO<sub>x</sub> 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<sub>2</sub> and NO<sub>x</sub> and a new percent reduction for SO<sub>2</sub> are calculated to show compliance with the standards.
- (f) For the initial performance test required under §60.8, compliance with the SO<sub>2</sub> emission limitations and percent reduction requirements under §60.43Da and the NO<sub>x</sub> emission limitation under §60.44Da is based on the average emission rates for SO<sub>2</sub>, NO<sub>x</sub>, and percent reduction for SO<sub>2</sub> 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<sub>2</sub> and NO<sub>x</sub> emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO<sub>2</sub> and NO<sub>x</sub> for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO<sub>x</sub> only), or emergency conditions (SO<sub>2</sub> only).
  - (2) Compliance with applicable SO<sub>2</sub> percentage reduction requirements is determined based on the average inlet and outlet SO<sub>2</sub> 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<sub>x</sub> emissions as  $1.194 \times 10^{-7}$  lb/scf-ppm times the average hourly NO<sub>x</sub> 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<sub>x</sub> emissions may be calculated by multiplying the hourly NO<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> and oxygen (O<sub>2</sub>) (or carbon dioxide (CO<sub>2</sub>)) and meet the requirements of §60.49Da. Alternatively, data from a NO<sub>x</sub> emission rate (i.e., NO<sub>x</sub>-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<sub>x</sub> emission rate at the outlet from the steam generating unit shall constitute the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission limitation in §60.44Da(d)(1) or (e)(1) as follows:
    - (i) The emission rate (E) of NO<sub>x</sub> 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<sub>x</sub> from the duct burner, ng/J (lb/MWh) gross output;

C<sub>sg</sub> = Average hourly concentration of NO<sub>x</sub> exiting the steam generating unit, ng/dscm (lb/dscf);

C<sub>te</sub> = Average hourly concentration of NO<sub>x</sub> in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q<sub>sg</sub> = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q<sub>te</sub> = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O<sub>sg</sub> = 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<sub>x</sub> concentrations (C<sub>sg</sub> and C<sub>te</sub>). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Q<sub>sg</sub> and Q<sub>te</sub>) 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<sub>x</sub> 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<sub>x</sub> 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.



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- (i) The emission rate (E) of NO<sub>x</sub> shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sg})}{O_{cc}} \quad (\text{Eq. 3})$$

Where:

E = Emission rate of NO<sub>x</sub> from the duct burner, ng/J (lb/MWh) gross output;

C<sub>sg</sub> = Average hourly concentration of NO<sub>x</sub> exiting the steam generating unit, ng/dscm (lb/dscf);

Q<sub>sg</sub> = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O<sub>cc</sub> = Average hourly gross energy output from entire combined cycle unit, J (MWh).

- (ii) The CEMS specified under §60.49Da for measuring NO<sub>x</sub> and O<sub>2</sub>(or CO<sub>2</sub>) shall be used to determine the average hourly NO<sub>x</sub> concentrations (C<sub>sg</sub>). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q<sub>sg</sub>) 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<sub>cc</sub>), 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<sub>x</sub> 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<sub>x</sub> shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \quad (\text{Eq. 4})$$

Where:

E = Emission rate of NO<sub>x</sub> from the duct burner, ng/J (lb/MWh) gross output;

ER<sub>sg</sub> = Average hourly emission rate of NO<sub>x</sub> 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<sub>cc</sub> = Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

O<sub>cc</sub> = 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<sub>x</sub> 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

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(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<sub>2</sub> emissions as  $1.660 \times 10^{-7}$  lb/scf-ppm times the average hourly SO<sub>2</sub> 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<sub>2</sub> emissions may be calculated by multiplying the hourly SO<sub>2</sub> 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.

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- (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 waiver 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.

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- (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 waiver 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.

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- (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 waiver 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

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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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> control device.
  - (2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) SO<sub>2</sub> emissions are only monitored as discharged to the atmosphere.

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- (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<sub>2</sub> emissions in place of a continuous SO<sub>2</sub> emission monitor at the inlet to the SO<sub>2</sub> control device as required under paragraph (b)(1) of this section.
- (4) If the owner or operator has installed and certified a SO<sub>2</sub> 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<sub>2</sub> or O<sub>2</sub> 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<sub>2</sub> emission limit in lb/MMBtu under §60.43Da:
    - (A) When relative accuracy testing is conducted, SO<sub>2</sub> concentration data and CO<sub>2</sub>(or O<sub>2</sub>) data are collected simultaneously; and
    - (B) In addition to meeting the applicable SO<sub>2</sub>and CO<sub>2</sub>(or O<sub>2</sub>) 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<sub>2</sub> and CO<sub>2</sub> (or O<sub>2</sub>) 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<sub>2</sub> 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<sub>x</sub> emissions discharged to the atmosphere; or
- (2) If the owner or operator has installed a NO<sub>x</sub> 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<sub>2</sub> or carbon dioxide (CO<sub>2</sub>) content of the flue gases at each location where SO<sub>2</sub> or NO<sub>x</sub> emissions are monitored. For affected facilities subject to a lb/MMBtu SO<sub>2</sub> emission limit under §60.43Da, if the owner or operator has installed and certified a CO<sub>2</sub> or O<sub>2</sub> 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<sub>2</sub> concentration monitoring system described in paragraph (b) of this section, to determine the SO<sub>2</sub> emission rate in lb/MMBtu. SO<sub>2</sub> 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.



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- (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<sub>2</sub> concentration at the same location as the SO<sub>2</sub> 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<sub>x</sub> concentration at the same location as the NO<sub>x</sub> 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<sub>2</sub> or CO<sub>2</sub> concentration at the same location as the O<sub>2</sub> or CO<sub>2</sub> 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<sub>2</sub>, SO<sub>2</sub>, and NO<sub>x</sub> concentrations, respectively.
  - (2) SO<sub>2</sub> or NO<sub>x</sub> (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N<sub>2</sub>, 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<sub>x</sub> shall be determined using one of the following procedures:
    - (i) Except as provided under paragraph (i)(3)(ii) of this section, NO<sub>x</sub> span values shall be determined as follows:



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<b>Fossil fuel</b>	<b>Span values for NO<sub>x</sub> (ppm)</b>
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<sub>x</sub> 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<sub>2</sub> CEMS at the inlet to the SO<sub>2</sub> control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO<sub>2</sub> 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<sub>2</sub> 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.

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- (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<sub>x</sub> standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NO<sub>x</sub> 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.

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- (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.

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- (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<sub>2</sub> or PM; or
  - (3) The affected source does not use post-combustion technology (except a wet scrubber) for reducing PM, SO<sub>2</sub>, 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.

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- (2) During each relative accuracy test run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O<sub>2</sub> (or CO<sub>2</sub>) 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<sub>2</sub> (or CO<sub>2</sub>), 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<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, and O<sub>2</sub> 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<sub>2</sub> and O<sub>2</sub> CEMS and for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> and O<sub>2</sub> CEMS and for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub>, CO<sub>2</sub>, and O<sub>2</sub> CEMS and for NO<sub>x</sub> 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

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in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO<sub>2</sub> (regardless of the SO<sub>2</sub> emission level during the RATA), and for NO<sub>x</sub> when the average NO<sub>x</sub> 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<sub>2</sub> and NO<sub>x</sub>. 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<sub>2</sub>) 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<sub>2</sub> concentration. The O<sub>2</sub> 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<sub>2</sub> traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O<sub>2</sub> traverse points. If the grab sampling procedure is used, the O<sub>2</sub> concentration for the run shall be the arithmetic mean of the sample O<sub>2</sub> 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<sub>2</sub> standards in §60.43Da as follows:
- (1) The percent of potential SO<sub>2</sub> 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<sub>2</sub> emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO<sub>2</sub> control system, percent.

- (2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction (%R<sub>f</sub>) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrosulfurization 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<sub>2</sub> reduction (%R<sub>g</sub>) of any SO<sub>2</sub> 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

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if the percent reduction is calculated using the average emission rate from the SO<sub>2</sub> control device and the average SO<sub>2</sub> 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<sub>2</sub> and CO<sub>2</sub> or O<sub>2</sub>.
- (d) The owner or operator shall determine compliance with the NO<sub>x</sub> 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<sub>x</sub>.
  - (2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub>.
- (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<sub>c</sub> factor (CO<sub>2</sub>) 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<sub>2</sub> shall be determined in the same manner as the O<sub>2</sub> concentration.
- (f) Electric utility combined cycle gas turbines are performance tested for PM, SO<sub>2</sub>, and NO<sub>x</sub> using the procedures of Method 19 of appendix A of this part. The SO<sub>2</sub> and NO<sub>x</sub> 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.

$$ER_{\text{cogen}} = \frac{M}{\left( V_{\text{grid}} + 0.75 \times V_{\text{process}} \right)} \quad (\text{Eq. 5})$$

Where:

ER<sub>cogen</sub> = 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<sub>grid</sub> = Amount of energy sent to the grid over the same compliance period (MWh); and

V<sub>process</sub> = Amount of energy converted to steam for process use over the same compliance period (MWh).

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- (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:

$$E_h = KC_h Q_h t_h \quad (\text{Eq. 6})$$

Where:

$E_h$  = Hg mass emissions for the hour, (lb);

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/ $\mu$ gm-scf;

$C_h$  = Hourly Hg concentration, wet basis, ( $\mu$ gm/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,  $t_h = 0.50$  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:

$$E_h = KC_h Q_h t_h (1 - B_{ws}) \quad (\text{Eq. 7})$$

Where:

$E_h$  = Hg mass emissions for the hour, (lb);

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/ $\mu$ gm-scf;

$C_h$  = Hourly Hg concentration, dry basis, ( $\mu$ gm/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<sub>2</sub>O,  $B_{ws} = 0.08$ ).



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- (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):

$$M = \sum_{h=1}^n E_h \quad (\text{Eq. 8})$$

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.

$$ER = \frac{M}{P} \quad (\text{Eq. 9})$$

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.

$$E_{avg} = \frac{\sum_{i=1}^{12} (ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \quad (\text{Eq. 10})$$

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 ( $Hg^0$   $HgCl_2$ ) 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:  $Hg^0$  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

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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<sub>2</sub>, NO<sub>x</sub>, 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<sub>2</sub> and NO<sub>x</sub> the following information is reported to the Administrator for each 24-hour period.
  - (1) Calendar date.
  - (2) The average SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> 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<sub>x</sub> only), emergency conditions (SO<sub>2</sub> 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 ( $n_o$ ) and inlet emission rates ( $n_i$ ) as applicable.
  - (2) The standard deviation of hourly averages for outlet emission rates ( $s_o$ ) and inlet emission rates ( $s_i$ ) as applicable.
  - (3) The lower confidence limit for the mean outlet emission rate ( $E_o^*$ ) and the upper confidence limit for the mean inlet emission rate ( $E_i^*$ ) as applicable.
  - (4) The applicable potential combustion concentration.
  - (5) The ratio of the upper confidence limit for the mean outlet emission rate ( $E_o^*$ ) and the allowable emission rate ( $E_{std}$ ) as applicable.
- (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;

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- (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<sub>2</sub> 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<sub>2</sub> or NO<sub>x</sub> 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

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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<sub>2</sub> and/or NO<sub>x</sub> 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).

**Updated 4/27/06**

**Source [44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000; 69 FR 41346, July 8, 2004]**

## **Subpart GG-Standards of Performance for Stationary Gas Turbines**

### **§ 60.330 Applicability and designation of affected facility.**

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.

### **§ 60.331 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.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

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- (f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.
- (g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
- (h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.
- (i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.
- (j) *Base load* means the load level at which a gas turbine is normally operated.
- (k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.
- (l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.
- (m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.
- (n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.
- (o) *Garrison facility* means any permanent military installation.
- (p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.
- (q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.
- (r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.
- (s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.
- (t) *Excess emissions* means a specified averaging period over which either:
- (1) The NO<sub>x</sub> emissions are higher than the applicable emission limit in Sec. 60.332;
  - (2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 60.333; or
  - (3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) Natural gas means 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 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) 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.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

#### § 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

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

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

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO<sub>x</sub> emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

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

F = NO<sub>x</sub> emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

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

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO<sub>x</sub> emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

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

F = NO<sub>x</sub> emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO<sub>x</sub> allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO<sub>x</sub> emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under Sec. 60.8 as follows:

Fuel-bound nitrogen (% by weight)	F (NO <sub>x</sub> % by volume)
N≤0.015.....	0
0.015<N≤0.1.....	0.04(N)
0.1<N≤0.25.....	0.004+0.0067(N-0.1)
N>0.25.....	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by Sec. 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

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

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

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- (d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in § 60.332(b) shall comply with paragraph (a)(2) of this section.
- (e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.
- (f) Stationary gas turbines using water or steam injection for control of NO<sub>x</sub> emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.
- (g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.
- (h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.
- (i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.
- (j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.
- (k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.
- (l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

**§ 60.333 Standard for sulfur dioxide.**

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

- (a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.
- (b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

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**§ 60.334 Monitoring of operations.**

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO<sub>x</sub> emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO<sub>x</sub> emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO<sub>x</sub> and O<sub>2</sub> monitors. As an alternative, a CO<sub>2</sub> monitor may be used to adjust the measured NO<sub>x</sub> concentrations to 15 percent O<sub>2</sub> by either converting the CO<sub>2</sub> hourly averages to equivalent O<sub>2</sub> concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O<sub>2</sub>, or by using the CO<sub>2</sub> readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO<sub>x</sub> and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO<sub>x</sub>) and a percent O<sub>2</sub> basis for oxygen; or

(ii) On a ppm at 15 percent O<sub>2</sub> basis; or

(iii) On a ppm basis (for NO<sub>x</sub>) and a percent CO<sub>2</sub> basis (for a CO<sub>2</sub> monitor that uses the procedures in Method 20 to correct the NO<sub>x</sub> data to 15 percent O<sub>2</sub>).

(2) As specified in Sec. 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in Sec. 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO<sub>x</sub> and diluent, the data acquisition and handling system must calculate and record the hourly NO<sub>x</sub> emissions in the units of the applicable NO<sub>x</sub> emission standard under Sec. 60.332(a), i.e., percent NO<sub>x</sub> by volume, dry basis, corrected to 15 percent O<sub>2</sub> and International Organization for Standardization (ISO) standard conditions (if required as given in Sec. 60.335(b)(1)). For any hour in which the hourly average O<sub>2</sub> concentration exceeds 19.0 percent O<sub>2</sub>, a diluent cap value of 19.0 percent O<sub>2</sub> may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H<sub>o</sub>), minimum ambient temperature (T<sub>a</sub>), and minimum combustor inlet absolute pressure (P<sub>o</sub>) into the ISO correction equation.

(iii) If the owner or operator has installed a NO<sub>x</sub> 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, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in Sec. 60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO<sub>x</sub> emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO<sub>x</sub> emission limit under Sec. 60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO<sub>x</sub> emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO<sub>x</sub> CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO<sub>x</sub> emissions, may, but is not required to, elect to use a NO<sub>x</sub> CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO<sub>x</sub> emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO<sub>x</sub> formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode.

(3) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO<sub>x</sub> emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in Sec. 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under Sec. 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO<sub>x</sub> emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in Sec. 75.19 of this chapter or the NO<sub>x</sub> emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in Sec. 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

## SUBPART GG-STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in Sec. 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see Sec. 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in Sec. 60.332). The nitrogen content of the fuel shall be determined using methods described in Sec. 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Sec. 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) Gaseous fuel. Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) Custom schedules. Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Sec. 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in Sec. 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under Sec. 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with Sec. 60.332, as established during the performance

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test required in Sec. 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in Sec. 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO<sub>x</sub> and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO<sub>x</sub> concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO<sub>x</sub> concentration" is the arithmetic average of the average NO<sub>x</sub> concentration measured by the CEMS for a given hour (corrected to 15 percent O<sub>2</sub> and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO<sub>x</sub> concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO<sub>x</sub> concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO<sub>x</sub> emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

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(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under Sec. 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

#### **Sec. 60.335 Test methods and procedures.**

(a) The owner or operator shall conduct the performance tests required in Sec. 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO<sub>x</sub> and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO<sub>x</sub> and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

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(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO<sub>x</sub> concentrations, normalized to 15 percent O<sub>2</sub>, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO<sub>x</sub> concentration during the stratification test; or

(B) If each of the individual traverse point NO<sub>x</sub> concentrations, normalized to 15 percent O<sub>2</sub>, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in Sec. 60.332 and shall meet the performance test requirements of Sec. 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO<sub>xo</sub>) corrected to 15 percent O<sub>2</sub> shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$\text{NO}_x = (\text{NO}_{x_o})(P_r/P_o)^{0.5} e^{19(H_o - 0.00633)} (288[\text{deg}]\text{K}/T_a)^{1.53}$$

Where:

NO<sub>x</sub> = emission concentration of NO<sub>x</sub> at 15 percent O<sub>2</sub> and ISO standard ambient conditions, ppm by volume, dry basis,

NO<sub>xo</sub> = mean observed NO<sub>x</sub> concentration, ppm by volume, dry basis, at 15 percent O<sub>2</sub>,

P<sub>r</sub> = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P<sub>o</sub> = observed combustor inlet absolute pressure at test, mm Hg,

H<sub>o</sub> = observed humidity of ambient air, g H<sub>2</sub>O/g air,

e = transcendental constant, 2.718, and

T<sub>a</sub> = ambient temperature, [deg]K.

(2) The 3-run performance test required by Sec. 60.8 must be performed within 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in Sec. 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO<sub>x</sub> emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO<sub>x</sub> emission limit in Sec. 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO<sub>x</sub> with no additional post-combustion NO<sub>x</sub> control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00



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(incorporated by reference, see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332 NO<sub>x</sub> emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in Sec. 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in Sec. 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO<sub>x</sub> CEMS under Sec. 60.334(e), then the initial performance test required under Sec. 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO<sub>x</sub> emission limit under Sec. 60.332 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under Sec. 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO<sub>x</sub> emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in Sec. 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under Sec. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

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(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in Sec. 60.8 to ISO standard day conditions.

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**RR1. Reporting Schedule.** This table summarizes information for convenience purposes only. It does not supersede any of the terms or conditions of this permit.

<b>Report</b>	<b>Reporting Deadline(s)</b>	<b>Related Condition(s)</b>
Plant Problems/Permit Deviations	Immediately upon occurrence (See RR2.d.)	RR2, 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

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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)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.]

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**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. A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:
  - (1) Typographical errors noted in the permit;
  - (2) Name, address or phone number change from that in the permit;
  - (3) A change requiring more frequent monitoring or reporting by the permittee;
  - (4) A change in ownership or operational control of a facility, subject to the following provisions:
    - (a) The Department determines that no other change in the permit is necessary;
    - (b) 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
    - (c) The new permittee has notified the Department of the effective date of sale or legal transfer.
  - (5) 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;
  - (6) 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
  - (7) Any other similar minor administrative change at the source.
- b. Upon receipt of any such notification, the Department shall within 60 days correct the permit and provide a corrected copy to the owner.

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- c. After first notifying the owner, the Department shall correct any permit in which it discovers errors of the types listed at Rules 62-210.360(1)(a) and (b), F.A.C., and provide a corrected copy to the owner.
- d. For Title V source permits, other than general permits, a copy of the corrected permit shall be provided to EPA and any approved local air program in the county where the facility or any part of the facility is located.

[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/forms.htm>.

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- a. Major Air Pollution Source Annual Emissions Fee Form (Effective 01/03/2001).
  - 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)]

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**FACILITY-WIDE TESTING REQUIREMENTS**

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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



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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.

<b>TABLE 297.310-1 CALIBRATION SCHEDULE</b>			
<b>ITEM</b>	<b>MINIMUM CALIBRATION FREQUENCY</b>	<b>REFERENCE INSTRUMENT</b>	<b>TOLERANCE</b>
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.]

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**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.** The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. 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.

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- (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

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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

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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

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are true and correct to his knowledge.  
[Rule 62-297.310(8), F.A.C.]

**APPENDIX TV**  
**TITLE V GENERAL CONDITIONS**  
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**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, applicable requirements of the CAIR Program, and applicable requirements of the Hg Budget Trading 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;
  - 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.,

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**TITLE V GENERAL CONDITIONS**  
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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, the CAIR Program. [Rule 62-213.460, F.A.C.]

**Permit Procedures**

- TV16. 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).
- TV17. 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.]



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**TV18. 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.

**TV19. 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.]

**TV20. 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(7), 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.]

**TV21. 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.]

**TV22. 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.]

**TV23. 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**

**TV24. 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

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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.]

**TV25. 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.)]

**TV26. 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.]

**TV27. 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**

**TV28. 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.]

**TV29. 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;

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- (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.]

**TV30. 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

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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.

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- 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**

**TV31. 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**

**TV32. 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.]

**TV33. 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.

**TV34. Open Burning Prohibited.** Unless otherwise authorized by Rule 62-296.320(3) or Chapter 62-256, F.A.C., open burning is prohibited.

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**APPENDIX U****LIST OF UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES**

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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.

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

<b>E.U. ID No.</b>	<b>Brief Description of Emissions Units and/or Activity</b>
003	Emergency Diesel Generator, Miscellaneous Mobile Equipment and Internal Combustion Engines
004	Painting of Plant Equipment and Non Halogenated Solvent Cleaning Operations
010	Ammonia Storage Tank
011	Black Start Diesel Engines (3)

**REFERENCED ATTACHMENTS**

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**The Following Attachments are Included for Applicant Convenience:**

Figure 1, Summary Report-Gaseous and Opacity Excess Emission and  
Monitoring System Performance (40 CFR 60, July, 1996).

Table H, Permit History.

Table 1, Summary of Air Pollutant Standards.

Table 2, Summary of Compliance Requirements.

# FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant (Circle One): SO<sub>2</sub> NO<sub>x</sub> TRS H<sub>2</sub>S CO Opacity

Reporting period dates: From \_\_\_\_\_ to \_\_\_\_\_

Company: \_\_\_\_\_

Emission Limitation: \_\_\_\_\_

Address: \_\_\_\_\_

Monitor Manufacturer: \_\_\_\_\_

Model No.: \_\_\_\_\_

Date of Latest CMS Certification or Audit: \_\_\_\_\_

Process Unit(s) Description: \_\_\_\_\_

Total source operating time in reporting period <sup>1</sup>: \_\_\_\_\_

Emission data summary <sup>1</sup>	CMS performance summary <sup>1</sup>
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 emissions .....	2. Total CMS Downtime .....
3. Total duration of excess emissions x (100) / [Total source operating time] ..... % <sup>2</sup>	3. [Total CMS Downtime] x (100) / [Total source operating time] ..... % <sup>2</sup>

<sup>1</sup> For opacity, record all times in minutes. For gases, record all times in hours.

<sup>2</sup> 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 40 CFR 60.7(c) shall be submitted.

Note: 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: \_\_\_\_\_ Date: \_\_\_\_\_

Title: \_\_\_\_\_



TABLE H

## PERMIT HISTORY

Table History, Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type <sup>1</sup>
001	Fossil Fuel Steam Generator, Unit 1	AO41-204804*	08/30/93	01/14/97	
002	Fossil Fuel Steam Generator, Unit 2	AO41-219341*	08/30/93	01/14/97	
All	Facility	0810010-001-AV	01/01/1999	12/31/2003	Initial
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-002-A0	05/27/1997	05/27/2002	Burn Boiler Cleaner & Propane
All	Facility	0810010-003-AV	01/01/1999	12/31/2003	Administration Correction
All	Facility	0810010-004-AV	01/01/1999	12/31/2003	Administration Correction
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-005-AC	12/23/1999	12/23/2000	AC (modification.)
006-009	Combined Cycle Unit 3A thru 3D	0810010-006-AC	04/15/2003	12/31/2006	AC to install Combined Cycle Unit 3
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-007-AC	08/12/2002	07/01/2003	AC modification
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-008-AV	12/03/2002	12/31/2003	AV Revision
All	Facility	0810010-009-AV	01/01/2004	12/31/2008	AV Renewal
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-010-AC	07/05/2005	07/05/2010	AC (mod.) to allow reburn technology
005 to 009	Combined Cycle (CC) Unit 3A thru 3D	0810010-011-AV	10/12/2006	12/31/2008	AV Revision to incorporate CC Unit 3
005 to 009	Combined Cycle (CC) Unit 3A thru 3D	0810010-012-AC	08/30/2006	12/31/2006	AC Modification PSD-FL-328A (CC Unit 3)

<sup>1</sup> Project Type: Title V Permit (AV) - Initial, Revision, Renewal, or Administrative Correction; Air Construction Permit (AC): New, Modification; Extension (only for an AC); or, Withdrawn or Denied.

\*These permits were partially revised by Operation Permit Amendments, 0810010-002-AO.

**Table 1, Units 1 and 2 - Summary of Air Pollutant Emission Standards**

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions <sup>1</sup>		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
<b>VE</b> Steady State	Gas, Oil, Propane	8760	40% opacity					Rule 62-296.405(1)(a), F.A.C.	<b>A.5</b>
<b>VE</b> Soot Blowing or Load Change	Gas, Oil, Propane	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods during 3 hours of excess emissions)					Rule 62-210.700(3), F.A.C.	<b>A.6</b>
<b>PM</b> Steady State	Gas/Oil, Propane	8760	0.1 lb/mmBtu			865, 865	3,789, 43*	Rule 62-296.405(1)(b), F.A.C.	<b>A.7</b>
<b>PM</b> Soot Blowing or Load Change	Gas/Oil, Propane	8760	0.3 lb/mmBtu			2,595, 2,595	1,421, 130*	Rule 62-210.700(3), F.A.C.	<b>A.8</b>

\* The equivalent annual emissions for propane are based on the expected annual usage of propane reported by the applicant primarily as a startup fuel. Propane usage is not limited by this permit.

**Table 1, Units 1 and 2 - Summary of Air Pollutant Emission Standards**

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Pollutant	Fuels	Hours per Year	Allowable Emissions			Equivalent Emissions <sup>1</sup>		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
SO <sub>2</sub>	Oil, Propane	8760	1.1 lb/mmBtu			9,515 (oil)	41,676 (oil)	Rules 62-213.440 & 62-296.405(1)(c)1.g., F.A.C.	<b>A.9</b>
NO <sub>x</sub>	Gas/Oil Propane	8760	0.30 lb/mmBtu			2,595 2,712	11,366 11,879	Rules 62-296.405(1)(d)2., F.A.C.	<b>A.10</b>

Notes:

<sup>1</sup> The "Equivalent Emissions" listed are for informational purposes only. Equivalent emissions are for each emissions unit.

**Table 1-2, Unit 3 - Summary of Air Pollutant Emission Standards**

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

Emission Unit (EU) ID No.	Brief Description: "4 on 1" Combined Cycle Unit 3
005	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator
006	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
007	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator

**Combined Cycle Operation Mode**

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions*			Equivalent Emissions <sup>1</sup>		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
NO <sub>x</sub>	Natural Gas	8760	2.5 ppmvd@15%O <sub>2</sub>	16.3 23.6			71.4 103.37	Rule 62-212.400, F.A.C.	B.9 and B.10
CO	Natural Gas	8760	7.4 10 ppmvd@15%O <sub>2</sub>	27.5 37.2			120.5 162.7	Rule 62-212.400, F.A.C.	B.9 and B.10
VOC	Natural Gas	8760	1.3 4.0 ppmvd@15%O <sub>2</sub>	2.8 10.5			12.3	Rule 62-212.400, F.A.C.	B.9 and B.10
VE	Natural Gas	8760	10 % opacity				15.1	Rule 62-212.400, F.A.C.	B.9 and B.10
Ammonia (NH <sub>3</sub> )	Natural Gas	8760	5 ppmvd@15%O <sub>2</sub>				49.4	Rule 62-212.400, F.A.C.	B.9 and B.10
PM/PM <sub>10</sub>	Natural Gas	8760	Fuel Specifications					Rule 62-212.400, F.A.C.	B.9 and B.10
SAM/SO <sub>2</sub>	Natural Gas	8760	Fuel Specifications					Rule 62-212.400, F.A.C.	B.9 and B.10

**Table 1-2, Unit 3 - Summary of Air Pollutant Emission Standards**

**Simple Cycle Operation Mode:**

After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1,000 hours per unit during any consecutive 12 months.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O <sub>2</sub>	lb/hour	ppmvd @ 15% O <sub>2</sub>
CO	Natural	Simple Cycle	7.4	27.5	8.0, 24-hr
	Gas	Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
NO <sub>x</sub>	Natural	Simple Cycle	9.0	58.7	9.0, 24-hr
	Gas	Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/PK	15.0	95.3	15.0, 24-hr
PM/PM <sub>10</sub>	Natural	Simple or Combined Cycle	Fuel Specifications		
	Gas	Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO <sub>2</sub>	Natural Gas	Simple or Combined Cycle	Fuel Specifications		
VOC	Natural Gas	Simple or Normal Combined Cycle	1.3	2.8	NA

**Table 2, Unit 1 and 2 - Summary of Compliance Requirements**

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

<b>Emissions Unit</b>	<b>Brief Description</b>
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Pollutant or Parameter	Fuels	Compliance Method	Testing Frequency	Frequency Base Date <sup>1</sup>	Minimum Compliance Test Duration	CMS <sup>2</sup>	See Permit Condition(s)
<b>SO<sub>2</sub></b>	Oil	Fuel sampling & analysis	As received			Yes	<b>A.15, A.20, A.25</b>
<b>NO<sub>x</sub></b>	Gas, Oil, Propane	Continuous Emissions Monitor	Continuous			Yes	<b>A.10, A.15</b>
<b>PM</b>	Oil, Propane	Rule 62-296.405(1)(e)2	Annual	July	3 hours		<b>A.15, A.24</b>
<b>VE</b>	Oil, Propane	DEP Method 9	Annual	July	1 hour	Yes	<b>A.15, A.16</b>
<b>On-spec. Used Oil</b>		Record Keeping and Analysis	As fired				<b>A.33</b>

Notes:

<sup>1</sup> Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

<sup>2</sup> CMS = continuous monitoring system

**Table 2-2, Unit 3 - Summary of Compliance Requirements**

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

Emission Unit (EU) ID No.	Brief Description: "4 on 1" Combined Cycle Unit 3
005	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator
006	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
007	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator

Pollutant or Parameter	Fuel <sup>3</sup>	Compliance Reference Method	Testing Frequency	Frequency Base Date <sup>1</sup>	Minimum Compliance Stack Test Duration	CMS <sup>2</sup>	See Permit Condition(s)
NO <sub>x</sub>	N.G.	CEMS. 24-hour block average Method 7E or 20 for lb/hr 3-run average	Annual	June	3 hours	Yes	B.10, B.19, B.20, B.21
CO	N.G.	CEMS. 24-hour block average Method 10 for lb/hr 3-run average	Annual	June	3 hours	Yes	B.10, B.20, B.21, B.22
PM	N.G.	Visible Emissions (VE) subrogate	Annual	June			B.9, B.10
VOC	N.G.	EPA Method 25A. Optionally Method 18.	Initial	June	3 hours		B.10, B.20, B.21, B.22
VE	N.G.	Method 9	Annual	June	6 minutes block average		B.10
SO <sub>2</sub> /SAM	N.G.	Fuel Specifications	As received	June			B. 9, B.10, B.19
NH <sub>3</sub>	N.G.	CTM-027	Initial	June			B.19, B.20, B.21

Notes:

<sup>1</sup> Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

<sup>2</sup> CMS = continuous monitoring system

<sup>3</sup> N.G: Natural Gas

**Simple Cycle Operation Mode:**

After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1,000 hours per unit during any consecutive 12 months.

**Friday, Barbara**

---

**To:** paul\_plotkin@fpl.com  
**Cc:** 'KKosky@Golder.com'; Sheila\_Wilkinson@fpl.com; Nasca, Mara;  
Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Attachments:** 0810010014NoticeofFinalPermit.pdf; 0810010014NoticeofFinalPermit.pdf

Dear Sir/ Madam:

Attached is the official **Written Notice of Intent to Issue Air 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". **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/0810010.014.AV.F\\_pdf.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0810010.014.AV.F_pdf.zip)

Attention: Tom Cascio

Owner/Company Name: FLORIDA POWER and LIGHT (PMT)

Facility Name: MANATEE POWER PLANT

Project Number: 0810010-014-AV

Permit Status: FINAL

Permit Activity: PERMIT RENEWAL

Facility County: MANATEE

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/eproducts/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 at (850)488-0114.

Barbara Friday

Bureau of Air Regulation

Division of Air Resource Management (DARM)

(850)921-9524



## Friday, Barbara

---

**From:** Exchange Administrator  
**Sent:** Friday, December 12, 2008 10:23 AM  
**To:** Friday, Barbara  
**Subject:** Delivery Status Notification (Relay)  
**Attachments:** ATT616913.txt; FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT;  
0810010-014-AV

This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

[paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
[Sheila\\_Wilkinson@fpl.com](mailto:Sheila_Wilkinson@fpl.com)

## Friday, Barbara

---

**From:** Plotkin, Paul [Paul.Plotkin@fpl.com]  
**To:** Friday, Barbara  
**Sent:** Friday, December 12, 2008 10:34 AM  
**Subject:** Read: FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV

Your message

**To:** [Paul.Plotkin@fpl.com](mailto:Paul.Plotkin@fpl.com)  
**Subject:**

was read on 12/12/2008 10:34 AM.

## Friday, Barbara

---

**From:** Wilkinson, Sheila M [Sheila.M.Wilkinson@fpl.com]  
**To:** Friday, Barbara  
**Sent:** Friday, December 12, 2008 12:13 PM  
**Subject:** Read: FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV

Your message

**To:** [Sheila.M.Wilkinson@fpl.com](mailto:Sheila.M.Wilkinson@fpl.com)  
**Subject:**

was read on 12/12/2008 12:13 PM.

## Friday, Barbara

---

**From:** Mail Delivery System [MAILER-DAEMON@mx1.golder.com]  
**Sent:** Friday, December 12, 2008 10:23 AM  
**To:** Friday, Barbara  
**Subject:** Successful Mail Delivery Report  
**Attachments:** Delivery report; Message Headers

This is the mail system at host mx1.golder.com.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<KKosky@Golder.com>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK, sent  
494281B8\_24915\_37745\_1 4F48C1CF0AED

**Friday, Barbara**

---

**From:** System Administrator  
**To:** Nasca, Mara  
**Sent:** Friday, December 12, 2008 10:22 AM  
**Subject:** Delivered:FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT;  
0810010-014-AV

Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was delivered to the following recipient(s):

Nasca, Mara on 12/12/2008 10:22 AM

## Friday, Barbara

---

**From:** Nasca, Mara  
**To:** Friday, Barbara  
**Sent:** Friday, December 12, 2008 10:24 AM  
**Subject:** Read: FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV

Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was read on 12/12/2008 10:24 AM.

## Friday, Barbara

---

**From:** Mail Delivery System [MAILER-DAEMON@mseive01.rtp.epa.gov]  
**Sent:** Friday, December 12, 2008 10:23 AM  
**To:** Friday, Barbara  
**Subject:** Successful Mail Delivery Report  
**Attachments:** Delivery report; Message Headers

This is the mail system at host mseive01.rtp.epa.gov.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<Forney.Kathleen@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250  
OK, sent 494281BA\_32715\_4561\_1 5C5B34439E

<Oquendo.Ana@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK,  
sent 494281BA\_32715\_4561\_1 5C5B34439E

## Friday, Barbara

---

**From:** System Administrator  
**To:** Cascio, Tom; Gibson, Victoria  
**Sent:** Friday, December 12, 2008 10:22 AM  
**Subject:** Delivered:FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT;  
0810010-014-AV

Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was delivered to the following recipient(s):

Cascio, Tom on 12/12/2008 10:22 AM  
Gibson, Victoria on 12/12/2008 10:22 AM



## Friday, Barbara

---

**From:** Gibson, Victoria  
**To:** Friday, Barbara  
**Sent:** Friday, December 12, 2008 10:32 AM  
**Subject:** Read: FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV

Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was read on 12/12/2008 10:32 AM.

## Friday, Barbara

---

**From:** Cascio, Tom  
**To:** Friday, Barbara  
**Sent:** Friday, December 12, 2008 10:31 AM  
**Subject:** Read: FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV

Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was read on 12/12/2008 10:31 AM.

## Friday, Barbara

---

**From:** System Administrator  
**To:** Holtom, Jonathan  
**Sent:** Friday, December 12, 2008 10:22 AM  
**Subject:** Delivered:FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT;  
0810010-014-AV

### Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was delivered to the following recipient(s):

Holtom, Jonathan on 12/12/2008 10:22 AM

## Friday, Barbara

---

**From:** Holtom, Jonathan  
**To:** Friday, Barbara  
**Sent:** Friday, December 12, 2008 10:39 AM  
**Subject:** Read: FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV

Your message

**To:** [paul\\_plotkin@fpl.com](mailto:paul_plotkin@fpl.com)  
**Cc:** 'KKosky@Golder.com'; [Sheila.Wilkinson@fpl.com](mailto:Sheila.Wilkinson@fpl.com); Nasca, Mara;  
[Forney.Kathleen@epamail.epa.gov](mailto:Forney.Kathleen@epamail.epa.gov); [Oquendo.Ana@epamail.epa.gov](mailto:Oquendo.Ana@epamail.epa.gov); Gibson, Victoria;  
Cascio, Tom; Holtom, Jonathan  
**Subject:** FLORIDA POWER & LIGHT COMPANY - MANATEE POWER PLANT; 0810010-014-AV  
**Sent:** 12/12/2008 10:22 AM

was read on 12/12/2008 10:39 AM.