Contents

The Following Appendices Are Enforceable Parts of This Permit:

Appendix A - Glossary.

Appendix BOP - Best Operational Practices for Startup and Shutdown.

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

Appendix RR - Facility-wide Reporting Requirements.

Appendix TR - Facility-wide Testing Requirements.

Appendix TV - Title V General Conditions.

Appendix 40 CFR 60, Subpart A - General Provisions.

Appendix 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

Appendix 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines.

Appendix 40 CFR 60, Subpart Y - Standards of Performance for Coal Preparation and Processing Plants.

Appendix 40 CFR 63, Subpart A - General Provisions.

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

Appendix 40 CFR 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Referenced Attachments (Included for Convenience and Informational Purposes Only):

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

Table H, Permit History.

ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION NUMBERS

Abbreviations and Acronyms:

°F: degrees Fahrenheit
acfm: actual cubic feet per minute
AOR: Annual Operating Report
ARMS: Air Resource Management System (Department's database)
BACT: best available control technology
BHP: brake horsepower
Btu: British thermal units
CAA: Clean Air Act
CAAA: Clean Air Act Amendments of 1990
CAM: compliance assurance monitoring
CEMS: continuous emissions monitoring system
cfm: cubic feet per minute
CFR: Code of Federal Regulations
CI: compression ignition
CO: carbon monoxide
COMS: continuous opacity monitoring system
DARM: Division of Air Resource Management
DCA: Department of Community Affairs
DEP: Department of Environmental Protection
Department: Department of Environmental Protection
dscfm: dry standard cubic feet per minute
EPA: Environmental Protection Agency
ESP: electrostatic precipitator (control system for reducing particulate matter)
EU: emissions unit
F.A.C.: Florida Administrative Code
F.D.: forced draft
F.S.: Florida Statutes
FGR: flue gas recirculation
Fl: fluoride
ft^2: square feet
ft^3: cubic feet
g: grams
gpm: gallons per minute
gr: grains
HAP: hazardous air pollutant
HP: horsepower
Hg: mercury
ICE: internal combustion engine
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
kW: kilowatts
LAT: Latitude
lb: pound
lbs/hr: pounds per hour
LONG: Longitude
MACT: maximum achievable technology
mm: millimeter
MMBtu: million British thermal units
MSDS: material safety data sheets
MW: megawatt
NESHAP: National Emissions Standards for Hazardous Air Pollutants
NO_X: nitrogen oxides
NSPS: New Source Performance Standards
O&M: operation and maintenance
O_2: oxygen
ORIS: Office of Regulatory Information Systems
OS: Organic Solvent
Pb: lead
PM: particulate matter
PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less
PSD: prevention of significant deterioration
psi: pounds per square inch
PTE: potential to emit
RACT: reasonably available control technology
RATA: relative accuracy test audit
RICE: reciprocating internal combustion engine
RMP: Risk Management Plan
RO: Responsible Official
SAM: sulfuric acid mist
scf: standard cubic feet
scfm: standard cubic feet per minute
SI: spark ignition
SIC: standard industrial classification code
SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)
SOA: Specific Operating Agreement
SO_2: sulfur dioxide
TPH: tons per hour
TPY: tons per year
UTM: Universal Transverse Mercator coordinate system
VE: visible emissions
VOC: volatile organic compounds
x: By or times

ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION NUMBERS

Citations:

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

Code of Federal Regulations:

Example: **[40 CFR 60.334]**

Where:

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

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

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

Where:

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

Identification Numbers:

Facility Identification (ID) Number:

Example: Facility ID No.: 1050221

Where:

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

Permit Numbers:

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

Where:

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

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

Where:

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

Back to Top

BEST OPERATIONAL PRACTICES FOR START UP AND SHUTDOWN.

PROCEDURES FOR STARTUP & SHUTDOWN OF UNIT #1

A. Startup

1. The Gas Turbine Generator (GTG) start is initiated by an operator. The start sequence performs the following steps automatically:
   a. A load commutating inverter raises the GTG speed to approximately 25% for a purge.
   b. The GTG is fired on natural gas and speed is increased to synchronous speed.
   c. The generator breaker closes automatically and the GTG is loaded to spinning reserve.
2. The operator increases GTG load to at least 55 MWs on Unit #1.
3. The GTG is then operated to meet system demand.
4. For syngas operation Unit #1, load is placed near 45% and transferred to syngas.
5. The GTG is then operated to meet system demand.

B. Shutdown

1. On Unit #1, the operator decreases GTG load to near 45%; the GTG is then transferred to distillate fuel.
2. The operator decreases GTG load to spinning reserve.
3. The operator initiates a shutdown on the GTG. The shutdown sequence performs the following steps automatically:
   a. The GTG load is reduced to 0%, and the generator breaker opens automatically.
   b. The GTG speed is reduced by reducing fuel until minimum firing speed is obtained.
   c. Fuel is secured to the GTG.
   d. The GTG coasts down until it reaches turning gear speed.

AUXILIARY BOILER START-UP AND SHUTDOWN PROCEDURES

Procedures for startup and shutdown of the Auxiliary Steam Boiler are as follows:

A. Startup

1. An operator initiates a start on the Auxiliary Boiler. The Auxiliary Boiler automatically purges.
2. After the purge, an operator initiates controls to ignite the diesel fuel to establish the main flame.
3. The boiler's controls automatically modulate the main flame to maintain operating steam pressure.

B. Shutdown

1. An operator initiates a shutdown the Auxiliary Boiler.
2. The Auxiliary Boiler fuel supply is shut-off extinguishing the flame. Next, the auxiliary boiler is purged and shutdown.

BEST OPERATIONAL PRACTICES FOR START UP AND SHUTDOWN.

PROCEDURES FOR STARTUP & SHUTDOWN OF UNIT #2 & #3

A. Startup

1. The Gas Turbine Generator (GTG) start is initiated by an operator. The start sequence performs the following steps automatically:
    a. A load commutating inverter raises the GTG speed to approximately 25% for a purge.
    b. The GTG is fired on natural gas or distillate fuel and speed is increased to synchronous speed.
    c. The generator breaker closes automatically and the GTG is loaded to spinning reserve.
2. The operator increases GTG load to at least 50%.
3. The GTG is then operated to meet system demand.

B. Shutdown

1. The operator decreases GTG load to spinning reserve.
2. The operator initiates a shutdown on the GTG. The shutdown sequence performs the following steps automatically:
    a. The GTG load is reduced to 0%, and the generator breaker opens automatically.
    b. The GTG speed is reduced by reducing fuel until minimum firing speed is obtained.
    c. Fuel is secured to the GTG.
    d. The GTG coasts down until it reaches turning gear speed.

PROCEDURES FOR STARTUP & SHUTDOWN OF UNIT #4 & #5

A. Startup

1. The Gas Turbine Generator (GTG) start is initiated by an operator. The start sequence performs the following steps automatically:
    a. A load commutating inverter raises the GTG speed to approximately 25% for a purge.
    b. The GTG is fired on natural gas and speed is increased to synchronous speed.
    c. The generator breaker closes automatically and the GTG is loaded to spinning reserve.
2. The operator increases GTG load to at least 50%.
3. The GTG is then operated to meet system demand.

B. Shutdown

1. The operator decreases GTG load to spinning reserve.
2. The operator initiates a shutdown on the GTG. The shutdown sequence performs the following steps automatically:
    a. The GTG load is reduced to 0%, and the generator breaker opens automatically.
    b. The GTG speed is reduced by reducing fuel until minimum firing speed is obtained.
    c. Fuel is secured to the GTG.
    d. The GTG coasts down until it reaches turning gear speed.

Back to Top

APPENDIX I

LIST OF INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source. The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Item	Description	Location
Miscellaneous Mobile (non-Road) Internal Combustion Engines	Air Compressors, Portable Welders, Pressure Washers	Plant - wide
Vacuum Pumps in Laboratory Operations	(1) Vacuum pump - used periodically	Polk Administration Lab
Equipment Used for Steam Cleaning	Used to clean various pieces of equipment around the plant -occasionally	Plant - wide
Miscellaneous Equipment Used Exclusively for Space Heating, other than boilers	There is no heat in the maintenance shop and these heaters are used there as the weather gets cold	Maintenance Shop
Laboratory Equipment Used Exclusively for Chemical or Physical Analyses	N/A	Polk Administration Lab
Brazing, Soldering, or Welding Equipment	Daily activity for construction and plant maintenance	Plant - wide
Petroleum Lubrication Systems	On all 5 combustion turbines and 1 steam turbine throughout the plant	Plant - wide
Vehicle Refueling Operations and associated fuel storage	(1) 2,000 gallon unleaded fuel; (1) re - fueling station	Polk Warehouse
Turbine Vapor Extractor	Pressure release for all 5 combustion turbines and 1 steam turbine throughout the plant	Plant - wide
Application of Fungicides, Herbicides, and Pesticides	Done occasionally throughout the plant	Plant - wide
Used Oil Storage Tanks	(1) 500 gallon	Lube Oil Building
Turbine and Lube Oil Storage Tanks	(5) 6,200 gallon; (1) 3,800 gallon	Plant - wide
Diesel Fuel Oil Storage Tanks	(2) 500 gallon; (2) 100 gallon	Plant - wide
No. 2 Fuel Oil Storage Tank	(1) 2.3 million gallon	North of the Gasification System

LIST OF INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES

Item	Description	Location
Wastewater Treatment Equipment	Sand filters used for removing solids before discharged to the cooling reservoir	Cooling Reservoir
Storage Tanks Less than 550 gallons	(1) 500 gallon used oil storage tank; (6) 500 gallon temporary portable diesel storage tanks	Plant - wide
Inorganic Substance Storage Tanks greater than 550 gallons	(1) 10,360 gallon 50% NaOH; (1) 8,000 gallon 50% NaOH; (1) 140,000 gallon sulfuric acid product tank; (1) 5,000 gallon sulfuric acid tank; (1) 3,000 gallon sulfuric acid tank	Slurry Building; Slurry Building; Sulfuric Acid Plant; Service Water Production Area; Cooling Reservoir
Architectural (equipment) Maintenance Painting	Upkeep of various buildings around the plant	Plant - wide
Diesel and No. 2 fuel oil truck unloading	Unloads into 2.3 million gallon tank or the diesel tanks	Truck Unloading
Covered belt conveyers transferring wet material	Slag after gasification is conveyed over to bin for storage	Gasification Area
Slag Beneficiation Process	Slag is beneficiated after gasification	Gasification Area
Surface Coating Operations	Painting Operations	Plant - wide
Sandblasting Activities	Use of black beauty or equivalent abrasive material when possible, is conducted in enclosed areas, and minimize fugitive emissions to the extent possible	Contractor Area
Fossil Fuel Steam Generators, hot water generators, and other external combustion heating units	(1) 9 MMBtu/hr; (1) 15 MMBtu/hr; (1) 19.1 MMBtu/hr	Sulfuric Acid Plant & Gasification Area
Brine Stack	Evaporating water from the brine slurry	Brine Plant
Vibrating Screen	Ungasified material is passed over the vibrating screen separating the carbon from the mineral matter in order to recycle the carbon back into the gasification process	Gasification Area
Inlet and Supply Opening of Mill	Solid fuel and water is mixed in a rod mill to make a slurry. Water vapor and negligible amounts of ammonia and sour gas may be gassed off at this point	Gasification Area
Parts cleaning at work stations with lids closed when not in use	(1) About 3 feet by 4 feet solvent parts cleaner (non - hazardous)	Maintenance Shop

Back to Top

FACILITY-WIDE REPORTING REQUIREMENTS

(Version Dated 2/13/2014)

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

Report	**Reporting Deadline(s)**	**Related Condition(s)**
Plant Problems/Permit Deviations	Immediately upon occurrence (See RR2.d.)	RR2, RR3
Malfunction Excess Emissions Report	Quarterly (if requested)	RR3
Semi-Annual Monitoring Report	Every 6 months	RR4
Annual Operating Report	April 1	RR5
EAOR Title V Annual Emissions Fee Invoice and Fee Payment	April 1	RR6
Annual Statement of Compliance	Within 60 days after the end of each calendar year (or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement); and Within 60 days after submittal of a written agreement for transfer of responsibility, or Within 60 days after permanent shutdown.	RR7
Notification of Administrative Permit Corrections	As needed	RR8
Notification of Startup after Shutdown for More than One Year	Minimum of 60 days prior to the intended startup date or, if emergency startup, as soon as possible after the startup date is ascertained	RR9
Permit Renewal Application	225 days prior to the expiration date of permit	TV17
Test Reports	Maximum 45 days following compliance tests	TR8

{Permitting Note: See permit Section III. Emissions Units and Specific Conditions, for any additional Emission Unit-specific reporting requirements.}

RR2. Reports of Problems.

a. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules.

b. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   (1) A description of and cause of noncompliance; and
   (2) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

c. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes

aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

d. "Immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays; and, for purposes of Rule 62-4.160(15) and 40 CFR 70.6(a)(3)(iii)(B), "promptly" or "prompt" shall have the same meaning as "immediately".

[Rule 62-4.130, Rule 62-4.160(8), Rule 62-4.160(15), and Rule 62-213.440(1)(b), F.A.C.; 40 CFR 70.6(a)(3)(iii)(B)]

RR3. Reports of Deviations from Permit Requirements. The permittee shall report in accordance with the requirements of Rule 62-210.700(6), F.A.C. (below), and Rule 62-4.130, F.A.C. (condition RR2.), deviations from permit requirements, including those attributable to upset conditions as defined in the permit. Reports shall include the probable cause of such deviations, and any corrective actions or preventive measures taken. *Rule 62-210.700(6)*: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. (See condition RR2.). A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rules 62-213.440(1)(b)3.b., and 62-210.700(6)F.A.C.]

RR4. Semi-Annual Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports. [Rule 62-213.440(1)(b)3.a., F.A.C.]

RR5. Annual Operating Report. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1 of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. [Rules 62-210.370(2) & (3), 62-210.900 and 62-213.440(3)(a)2., F.A.C.]

RR6. EAOR Title V Annual Emissions Fee Invoice and Fee Payment. Each Title V source permitted to operate in Florida must pay between January 15 and April 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 March 1 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 April 1. If the fee is not postmarked or electronically submitted by April 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 one 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 years and shall be made available to the Department upon request.

c. A copy of the EAOR Title V Annual Emissions Fee Invoice generated by the electronic annual operating report (EAOR) application, must be submitted along with the annual emissions fee payment.

[Rules 62-210.370(3), 62-210.900 and 62-213.205, F.A.C.]

RR7. Annual Statement of Compliance.

a. The permittee shall submit a Statement of Compliance with all terms and conditions of the permit that includes all the provisions of 40 CFR 70.6(c)(5)(iii), incorporated by reference at Rule 62-204.800, F.A.C., using DEP Form No. 62-213.900(2). 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(2) as such statement of compliance so long as the responsible official identifies all reportable deviations from and all instances of non-compliance with any applicable requirements and includes all information required by the federal regulation relating to each reportable deviation and instance of non-compliance.

c. The responsible official may treat compliance with all other applicable requirements as a surrogate for compliance with Rule 62-296.320(2), Objectionable Odor Prohibited.

[Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

RR8. Notification of Administrative Permit Corrections.

A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:

a. Typographical errors noted in the permit;
b. Name, address or phone number change from that in the permit;
c. A change requiring more frequent monitoring or reporting by the permittee;
d. A change in ownership or operational control of a facility, subject to the following provisions:
   (1) The Department determines that no other change in the permit is necessary;
   (2) The permittee and proposed new permittee have submitted an Application for Transfer of Air Permit, and the Department has approved the transfer pursuant to Rule 62-210.300(7), F.A.C.; and
   (3) The new permittee has notified the Department of the effective date of sale or legal transfer.
e. Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), adopted and incorporated by reference at Rule 62-204.800, F.A.C., and changes made pursuant to Rules 62-214.340(1) and (2), F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;
f. Changes listed at 40 CFR 72.83(a)(11) and (12), adopted and incorporated by reference at Rule 62-204.800, F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 62-210.360(1)(e), F.A.C.; and
g. Any other similar minor administrative change at the source.

[Rule 62-210.360, F.A.C.]

RR9. Notification of Startup. The owners or operator of any emissions unit or facility which has a valid air operation permit which has been shut down more than one year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of 60 days prior to the intended startup date.

a. The notification shall include information as to the startup date, anticipated emission rates or pollutants released, changes to processes or control devices which will result in changes to emission rates, and any other conditions which may differ from the valid outstanding operation permit.

b. If, due to an emergency, a startup date is not known 60 days prior thereto, the owner shall notify the Department as soon as possible after the date of such startup is ascertained.

[Rule 62-210.300(5), F.A.C.]

RR10. Report Submission. The permittee shall submit all compliance related notifications and reports required of this permit to the Compliance Authority. {See front of permit for address and phone number.}

RR11. EPA Report Submission. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to: Air, Pesticides & Toxics Management Division, United States Environmental Protection Agency, Region 4, Sam Nunn Atlanta Federal Center, 61 Forsyth Street SW, Atlanta, GA 30303-8960. Phone: 404/562-9077.

RR12. Acid Rain Report Submission. Acid Rain Program Information shall be submitted, as necessary, to: Department of Environmental Protection, 2600 Blair Stone Road, Mail Station #5510, Tallahassee, Florida 32399-2400. Phone: 850/488-6140. Fax: 850/922-6979.

RR13. Report Certification. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C. [Rule 62-213.440(1)(b)3.c, F.A.C.]

RR14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information. [Rule 62-213.420(4), F.A.C.]

RR15. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA. Any permittee may claim confidentiality of any data or other information by complying with this procedure. [Rules 62-213.420(2), and 62-213.440(1)(d)6., F.A.C.]

RR16. Forms and Instructions. The forms used by the Department in the Title V source operation program are adopted and incorporated by reference in Rule 62-213.900, F.A.C. The forms are listed by rule number, which is also the form number, and with the subject, title, and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resource Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, by contacting the appropriate permitting authority or by accessing the Department's web site at: http://www.dep.state.fl.us/air/rules/forms.htm.

a. Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) (Effective 12/31/2013)

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)]

Back to Top

FACILITY-WIDE TESTING REQUIREMENTS

(Version Dated 9/12/2008)

Unless otherwise specified in the permit, the following testing requirements apply to each emissions unit for which testing is required. The terms "stack" and "duct" are used interchangeably in this appendix.

TR1. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

TR2. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

TR3. Calculation of Emission Rate. For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

TR4. Applicable Test Procedures.

a. *Required Sampling Time.*

(1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

(2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

(a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

(b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

(c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

b. *Minimum Sample Volume*. Unless otherwise specified in the applicable rule or test method, the minimum

sample volume per run shall be 25 dry standard cubic feet.

c. *Required Flow Rate Range.* For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

d. *Calibration of Sampling Equipment*. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

TABLE 297.310-1 CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/- 0.001" mean of at least three readings; Max. deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

e. *Allowed Modification to EPA Method 5*. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TR5. Determination of Process Variables.

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables,

such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. *Accuracy of Equipment*. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

TR6. Sampling Facilities. Permittees that are required to sample mass emissions from point sources shall install stack sampling ports and provide sampling facilities that meet the requirements of this condition. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities*. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities*. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports*.
   (1) All sampling ports shall have a minimum inside diameter of 3 inches.
   (2) The ports shall be capable of being sealed when not in use.
   (3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
   (4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
   (5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms*.
   (1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
   (2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
   (3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
   (4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches

below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform*.
   (1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
   (2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power*.
   (1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.
   (2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support*.
   (1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.
      (a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.
      (b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.
      (c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.
   (2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.
   (3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

TR7. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*
   (1) The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.
   (2) For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
   (3) The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
      (a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

(4) During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

(a) Visible emissions, if there is an applicable standard;

(b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

(c) Each NESHAP pollutant, if there is an applicable emission standard.

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

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

(7) For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

(8) Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

(9) The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(10) An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

c. *Waiver of Compliance Test Requirements.* If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.]

TR8. Test Reports.

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

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

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

(1) The type, location, and designation of the emissions unit tested.
(2) The facility at which the emissions unit is located.
(3) The owner or operator of the emissions unit.
(4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
(5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
(6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
(7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
(8) The date, starting time and duration of each sampling run.
(9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
(10) The number of points sampled and configuration and location of the sampling plane.
(11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
(12) The type, manufacturer and configuration of the sampling equipment used.
(13) Data related to the required calibration of the test equipment.
(14) Data on the identification, processing and weights of all filters used.
(15) Data on the types and amounts of any chemical solutions used.
(16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
(17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
(18) All measured and calculated data required to be determined by each applicable test procedure for each run.
(19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
(20) The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
(21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

Back to Top

TITLE V GENERAL CONDITIONS

(Version Dated 02/16/2012)

Operation

TV1. General Prohibition. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit. [Rule 62-4.030, Florida Administrative Code (F.A.C.)]

TV2. Validity. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department. [Rule 62-4.160(2), F.A.C.]

TV3. Proper Operation and Maintenance. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules. [Rule 62-4.160(6), F.A.C.]

TV4. Not Federally Enforceable. Health, Safety and Welfare. To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution, shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. [Rule 62-4.050(3), F.A.C.]

TV5. Continued Operation. An applicant making timely and complete application for permit, or for permit renewal, shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, and in accordance with applicable requirements of the Acid Rain Program and applicable requirements of the CAIR Program, until the conclusion of proceedings associated with its permit application or until the new permit becomes effective, whichever is later, provided the applicant complies with all the provisions of subparagraphs 62-213.420(1)(b)3., F.A.C. [Rules 62-213.420(1)(b)2., F.A.C.]

TV6. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation:

a. Permitted sources may change among those alternative methods of operation allowed by the source's permit as provided by the terms of the permit;
b. A permitted source may implement operating changes, as defined in Rule 62-210.200, F.A.C., after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
   (1) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
   (2) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
c. Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.

[Rule 62-213.410, F.A.C.]

TV7. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

Compliance

TV8. Compliance with Chapter 403, F.S., and Department Rules. Except as provided at Rule 62-213.460, Permit Shield, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules. [Rule 62-4.070(7), F.A.C.]

TV9. Compliance with Federal, State and Local Rules. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of a facility or an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law. [Rule 62-210.300, F.A.C.]

TV10. Binding and Enforceable. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions. [Rule 62-4.160(1), F.A.C.]

TV11. Timely Information. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly. [Rule 62-4.160(15), F.A.C.]

TV12. Halting Or Reduction Of Source Activity. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity. [Rule 62-213.440(1)(d)3., F.A.C.]

TV13. Final Permit Action. Any Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C. [Rule 62-213.440(1)(d)4., F.A.C.]

TV14. Sudden And Unforeseeable Events Beyond The Control Of The Source. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference. [Rule 62-213.440(1)(d)5., F.A.C.]

TV15. Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in this condition or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program or the CAIR Program. [Rule 62-213.460, F.A.C.]

TV16. Compliance With Federal Rules. A facility or emissions unit subject to any standard or requirement of 40 CFR, Part 60, 61, 63 or 65, adopted and incorporated by reference at Rule 62-204.800, F.A.C., shall comply with such standard or requirement. Nothing in this chapter shall relieve a facility or emissions unit from complying with such standard or requirement, provided, however, that where a facility or emissions unit is subject to a standard established in Rule 62-296, F.A.C., such standard shall also apply. [Rule 62-296.100(3), F.A.C.]

Permit Procedures

TV17. Permit Revision Procedures. The permittee shall revise its permit as required by Rules 62-213.400, 62-213.412, 62-213.420, 62-213.430 & 62-4.080, F.A.C.; and, in addition, the Department shall revise permits as provided in Rule 62-4.080, F.A.C. & 40 CFR 70.7(f).

TV18. Permit Renewal. The permittee shall renew its permit as required by Rules 62-4.090, 62.213.420(1) and 62-213.430(3), F.A.C. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information

identified in Rules 62-210.900(1) [Application for Air Permit - Long Form], 62-213.420(3) [Required Information], 62-213.420(6) [CAIR Part Form], F.A.C. Unless a Title V source submits a timely and complete application for permit renewal in accordance with the requirements this rule, the existing permit shall expire and the source's right to operate shall terminate. For purposes of a permit renewal, a timely application is one that is submitted 225 days before the expiration of a permit that expires on or after June 1, 2009. No Title V permit will be issued for a new term except through the renewal process. [Rules 62-213.420 & 62-213.430, F.A.C.]

TV19. Insignificant Emissions Units or Pollutant-Emitting Activities. The permittee shall identify and evaluate insignificant emissions units and activities as set forth in Rule 62-213.430(6), F.A.C.

TV20. Savings Clause. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect. [Rule 62-213.440(1)(d)1., F.A.C.]

TV21. Suspension and Revocation.

a. Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.
b. Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.
c. A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or his agent:
   (1) Submitted false or inaccurate information in his application or operational reports.
   (2) Has violated law, Department orders, rules or permit conditions.
   (3) Has failed to submit operational reports or other information required by Department rules.
   (4) Has refused lawful inspection under Section 403.091, F.S.
d. No revocation shall become effective except after notice is served by personal services, certified mail, or newspaper notice pursuant to Section 120.60(5), F.S., upon the person or persons named therein and a hearing held if requested within the time specified in the notice. The notice shall specify the provision of the law, or rule alleged to be violated, or the permit condition or Department order alleged to be violated, and the facts alleged to constitute a violation thereof.

[Rule 62-4.100, F.A.C.]

TV22. Not federally enforceable. Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules. [Rule 62-4.110, F.A.C.]

TV23. Emissions Unit Reclassification.

a. Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.
b. If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.

[Rule 62-210.300(6), F.A.C.]

TV24. Transfer of Permits. Per Rule 62-4.160(11), F.A.C., this permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any

violations occurring prior to the sale or legal transfer of the facility. The permittee shall also comply with the requirements of Rule 62-210.300(7), F.A.C., and use DEP Form No. 62-210.900(7). [Rules 62-4.160(11), 62-4.120, and 62-210.300(7), F.A.C.]

Rights, Title, Liability, and Agreements

TV25. Rights. As provided in Subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit. [Rule 62-4.160(3), F.A.C.]

TV26. Title. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. [Rule 62-4.160(4), (F.A.C.]

TV27. Liability. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department. [Rule 62-4.160(5), F.A.C.]

TV28. Agreements.

a. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:
   (1) Have access to and copy any records that must be kept under conditions of the permit;
   (2) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,
   (3) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.
b. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
c. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

[Rules 62-4.160(7), (9), and (10), F.A.C.]

Recordkeeping and Emissions Computation

TV29. Permit. The permittee shall keep this permit or a copy thereof at the work site of the permitted activity. [Rule 62-4.160(12), F.A.C.]

TV30. Recordkeeping.

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These

materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:
   (1) The date, exact place, and time of sampling or measurements, and the operating conditions at the time of sampling or measurement;
   (2) The person responsible for performing the sampling or measurements;
   (3) The dates analyses were performed;
   (4) The person and company that performed the analyses;
   (5) The analytical techniques or methods used;
   (6) The results of such analyses.

[Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

TV31. Emissions Computation. Pursuant to Rule 62-210.370, F.A.C., the following required methodologies are to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with Rule 62-210.370, F.A.C. Rule 62-210.370, F.A.C., is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

For any of the purposes specified above, the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

a. *Basic Approach*. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
   (1) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
   (2) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
   (3) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

b. *Continuous Emissions Monitoring System (CEMS)*.
   (1) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
      (a) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or,
      (b) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.
   (2) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

(a) A calibrated flowmeter that records data on a continuous basis, if available; or
(b) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(3) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

c. *Mass Balance Calculations.*

(1) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:
(a) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and,
(b) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(2) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(3) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

d. *Emission Factors.*

(1) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.
(a) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
(b) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.
(c) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

(2) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

e. *Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS*. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of

missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

f. *Accounting for Emissions During Periods of Startup and Shutdown.* In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

g. *Fugitive Emissions.* In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

h. *Recordkeeping.* The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(1) & (2), F.A.C.]

Responsible Official

TV32. Designation and Update. The permittee shall designate and update a responsible official as required by Rule 62-213.202, F.A.C.

Prohibitions and Restrictions

TV33. Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source. [40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

TV34. Refrigerant Requirements. Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Chapter 62-281, F.A.C.

TV35. Open Burning Prohibited. Open burning is prohibited unless performed in accordance with the provisions of Rule 62-296.320(3) or Chapter 62-256, F.A.

Back to Top

Link to 40 CFR 60, Subpart A - General Provisions

Back to Top

STANDARDS OF PERFORMANCE FOR INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

Link to 40 CFR 60, Subpart Db

Back to Top

STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

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: February 24, 2006

State Rule Effective Date: July 1, 2006

Standardized Conditions Revision Date: August 6, 2009

40 CFR Part 60, 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.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 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.

(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, combuster inlet pressure, combuster 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_X emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §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.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 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 §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

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

F = NO_X 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 §60.335(b)(1)) NO_X 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_X 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_X 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_X 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 §60.8 as follows:

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

Where:

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

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 §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.

(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_X 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.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 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 contains 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).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 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_X 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_X 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_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 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_2, or by using the CO_2 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_X 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_X) and a percent O_2 basis for oxygen; or

(ii) On a ppm at 15 percent O_2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

(2) As specified in §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 §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_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under §60.332(a), *i.e.* , percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 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 (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_X 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 §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_X 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_X emission limit under §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_X 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_X 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_X emissions, may, but is not required to, elect to use a NO_X 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_X 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_X 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_X mode.

(3) For any turbine that uses SCR to reduce NO_X 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_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §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 §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 §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_X 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 §75.19 of this chapter or the NO_X 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 §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.

(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 §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 §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 §60.332). The nitrogen content of the fuel shall be determined using methods described in §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 §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 §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 §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 §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 §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 §60.332, as established during the performance test required in §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 §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §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 §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_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_X concentration" is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X 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_X 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 §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §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_X 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.

(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 §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

§ 60.335 Test methods and procedures.

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

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X 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_X 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.

(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_X concentrations, normalized to 15 percent O_2, 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_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, 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 §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2 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:

$$NO_X = (NO_{Xo})(P_r/P_o)^{0.5}\ e19\ (Ho-0.00633)(288°K/T_a)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent $O_2$and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o = observed combustor inlet absolute pressure at test, mm Hg,

H_o = observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, °K.

(2) The 3-run performance test required by §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 §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_X 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_X emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §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 §60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §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 §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_X CEMS under §60.334(e), then the initial performance test required under §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_X emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

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

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X 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 §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* §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 §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* §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 §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:

(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 §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

Back to Top

STANDARDS OF PERFORMANCE FOR COAL PREPARATION PLANTS.

E.U. ID No.	Brief Description
005	Solid Fuel Handling System

Contents

§ 60.250 Applicability and designation of affected facility.
§ 60.251 Definitions.
§ 60.252 Standards for thermal dryers.
§ 60.253 Standards for pneumatic coal-cleaning equipment.
§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.
§ 60.255 Performance tests and other compliance requirements.
§ 60.256 Continuous monitoring requirements.
§ 60.257 Test methods and procedures.
§ 60.258 Reporting and recordkeeping.

Source: 74 FR 51977, Oct. 8, 2009, unless otherwise noted.

Back to Top

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.

(b) The provisions in § 60.251, § 60.252(a), § 60.253(a), § 60.254(a), § 60.255(a), and § 60.256(a) of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after October 27, 1974, and on or before April 28, 2008: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(c) The provisions in § 60.251, § 60.252(b)(1) and (c), § 60.253(b), § 60.254(b), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after April 28, 2008, and on or before May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(d) The provisions in § 60.251, § 60.252(b)(1) through (3), and (c), § 60.253(b), § 60.254(b) and (c), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles.

Back to Top

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Clean Air Act (Act) and in subpart A of this part.

(a) *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).

(b) *Bag leak detection system* means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a fabric filter to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

(c) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM D388 (incorporated by reference— *see* § 60.17).

(d) *Coal* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* § 60.17).

(2) For units constructed, reconstructed, or modified after May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* § 60.17), and coal refuse.

(e) *Coal preparation and processing plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(f) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts. Equipment located at the mine face is not considered to be part of the coal preparation and processing plant.

(g) *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.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Design controlled potential PM emissions rate* means the theoretical particulate matter (PM) emissions (Mg) that would result from the operation of a control device at its design emissions rate (grams per dry standard cubic meter (g/dscm)), multiplied by the maximum design flow rate (dry standard cubic meter per minute (dscm/min)), multiplied by 60 (minutes per hour (min/hr)), multiplied by 8,760 (hours per year (hr/yr)), divided by 1,000,000 (megagrams per gram (Mg/g)).

(j) *Indirect thermal dryer* means a thermal dryer that reduces the moisture content of coal through indirect heating of the coal through contact with a heat transfer medium. If the source of heat (the source of combustion or furnace) is subject to another subpart of this part, then the furnace and the associated emissions are not part of the affected facility. However, if the source of heat is not subject to another subpart of this part, then the furnace and the associated emissions are part of the affected facility.

(k) *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).

(l) *Mechanical vent* means any vent that uses a powered mechanical drive (machine) to induce air flow.

(m) *Open storage pile* means any facility, including storage area, that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility.

(n) *Operating day* means a 24-hour period between 12 midnight and the following midnight during which coal is prepared or processed at any time by the affected facility. It is not necessary that coal be prepared or processed the entire 24-hour period.

(o) *Pneumatic coal-cleaning equipment* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility which classifies coal by size or separates coal from refuse by application of air stream(s).

(p) *Potential combustion concentration* means the theoretical emissions (nanograms per joule (ng/J) or pounds per million British thermal units (lb/MMBtu) heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems, as determined using Method 19 of appendix A-7 of this part.

(q) *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).

(r) *Thermal dryer* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility in which the moisture content of coal is reduced by either contact with a heated gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heated heat transfer medium.

(s) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

Back to Top

§ 60.252 Standards for thermal dryers.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified on or before April 28, 2008, subject to the provisions of this subpart must meet the requirements in paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which contain PM in excess of 0.070 g/dscm (0.031 grains per dry standard cubic feet (gr/dscf)); and

(2) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which exhibit 20 percent opacity or greater.

(b) Except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after April 28, 2008, subject to the provisions of this subpart must meet the applicable standards for PM and opacity, as specified in paragraph (b)(1) of this section. In addition, and except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after May 29, 2009, subject to the provisions of this subpart must also meet the applicable standards for sulfur dioxide (SO_2), and combined nitrogen oxides (NO_X) and carbon monoxide (CO) as specified in paragraphs (b)(2) and (b)(3) of this section.

(1) The owner or operator must meet the requirements for PM emissions in paragraphs (b)(1)(i) through (iii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed or reconstructed after April 28, 2008, the owner or operator must meet the requirements of (b)(1)(i)(A) and (b)(1)(i)(B).

(A) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that contain PM in excess of 0.023 g/dscm (0.010 grains per dry standard cubic feet (gr/dscf)); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that exhibit 10 percent opacity or greater.

(ii) For each thermal dryer modified after April 28, 2008, the owner or operator must meet the requirements of paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B) of this section.

(A) The owner or operator must not cause to be discharged to the atmosphere from the affected facility any gases which contain PM in excess of 0.070 g/dscm (0.031 gr/dscf); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 20 percent opacity or greater.

(2) Except as provided in paragraph (b)(2)(iii) of this section, for each thermal dryer constructed, reconstructed, or modified after May 27, 2009, the owner or operator must meet the requirements for SO_2 emissions in either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 85 ng/J (0.20 lb/MMBtu) heat input; or

(ii) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that either contain SO_2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain SO_2 in excess of 10 percent of the potential combustion concentration (*i.e.*, the facility must achieve at least a 90 percent reduction of the potential combustion concentration and may not exceed a maximum emissions rate of 1.2 lb/MMBtu (520 ng/J)).

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to an SO_2 limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input are not subject to the SO_2 limits of this section.

(3) Except as provided in paragraph (b)(3)(iii) of this section, the owner or operator must meet the requirements for combined NO_X and CO emissions in paragraph (b)(3)(i) or (b)(3)(ii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain a combined concentration of NO_X and CO in excess of 280 ng/J (0.65 lb/MMBtu) heat input.

(ii) For each thermal dryer reconstructed or modified after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain combined concentration of NO_X and CO in excess of 430 ng/J (1.0 lb/MMBtu) heat input.

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to a NO_X limit and/or CO limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input, are not subject to the combined NO_X and CO limits of this section.

(c) Thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart.

Back to Top

§ 60.253 Standards for pneumatic coal-cleaning equipment.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed,

reconstructed, or modified on or before April 28, 2008, must meet the requirements of paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.040 g/dscm (0.017 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit 10 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) The owner of operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess or 0.023 g/dscm (0.010 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit greater than 5 percent opacity.

Back to Top

§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.

(1) Except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater.

(2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf).

(3) Equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section.

(c) The owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section.

(1) The fugitive coal dust emissions control plan must identify and describe the control measures the owner or operator will use to minimize fugitive coal dust emissions from each open storage pile.

(2) For open coal storage piles, the fugitive coal dust emissions control plan must require that one or more of the following control measures be used to minimize to the greatest extent practicable fugitive coal dust: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source (when the provisions of paragraph (c)(6) of this section are met),

use of a wind barrier, compaction, or use of a vegetative cover. The owner or operator must select, for inclusion in the fugitive coal dust emissions control plan, the control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Any owner or operator of an affected facility that is required to have a fugitive coal dust emissions control plan may petition the Administrator to approve, for inclusion in the plan for the affected facility, alternative control measures other than those specified in paragraph (c)(2) of this section as specified in paragraphs (c)(3)(i) through (iv) of this section.

(i) The petition must include a description of the alternative control measures, a copy of the fugitive coal dust emissions control plan for the affected facility that includes the alternative control measures, and information sufficient for EPA to evaluate the demonstrations required by paragraph (c)(3)(ii) of this section.

(ii) The owner or operator must either demonstrate that the fugitive coal dust emissions control plan that includes the alternate control measures will provide equivalent overall environmental protection or demonstrate that it is either economically or technically infeasible for the affected facility to use the control measures specifically identified in paragraph (c)(2).

(iii) While the petition is pending, the owner or operator must comply with the fugitive coal dust emissions control plan including the alternative control measures submitted with the petition. Operation in accordance with the plan submitted with the petition shall be deemed to constitute compliance with the requirement to operate in accordance with a fugitive coal dust emissions control plan that contains one of the control measures specifically identified in paragraph (c)(2) of this section while the petition is pending.

(iv) If the petition is approved by the Administrator, the alternative control measures will be approved for inclusion in the fugitive coal dust emissions control plan for the affected facility. In lieu of amending this subpart, a letter will be sent to the facility describing the specific control measures approved. The facility shall make any such letters and the applicable fugitive coal dust emissions control plan available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(4) The owner or operator must submit the fugitive coal dust emissions control plan to the Administrator or delegated authority as specified in paragraphs (c)(4)(i) and (c)(4)(ii) of this section.

(i) The plan must be submitted to the Administrator or delegated authority prior to startup of the new, reconstructed, or modified affected facility, or 30 days after the effective date of this rule, whichever is later.

(ii) The plan must be revised as needed to reflect any changing conditions at the source. Such revisions must be dated and submitted to the Administrator or delegated authority before a source can operate pursuant to these revisions. The Administrator or delegated authority may also object to such revisions as specified in paragraph (c)(5) of this section.

(5) The Administrator or delegated authority may object to the fugitive coal dust emissions control plan as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) The Administrator or delegated authority may object to any fugitive coal dust emissions control plan that it has determined does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(ii) If an objection is raised, the owner or operator, within 30 days from receipt of the objection, must submit a revised fugitive coal dust emissions control plan to the Administrator or delegated authority. The owner or operator must operate in accordance with the revised fugitive coal dust emissions control plan. The Administrator or delegated authority retain the right, under paragraph (c)(5) of this section, to object to the revised control plan if it determines the plan does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(6) Where appropriate chemical dust suppression agents are selected by the owner or operator as a control measure to minimize fugitive coal dust emissions, (1) only chemical dust suppressants with Occupational Safety and Health Administration (OSHA)-compliant material safety data sheets (MSDS) are to be allowed; (2) the MSDS must be included in the fugitive coal dust emissions control plan; and (3) the owner or operator must consider and document in the fugitive coal dust emissions control plan the site-specific impacts associated with the use of such chemical dust suppressants.

Back to Top

§ 60.255 Performance tests and other compliance requirements.

(a) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emission standards using the methods identified in § 60.257.

(b) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of § 60.8 and the methods identified in § 60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.

(1) For each affected facility subject to a PM, SO_2 , or combined NO_X and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 30 calendar days after the next operating day.

(2) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in § 60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.

(c) If any affected coal processing and conveying equipment (*e.g.*, breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction,

or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in § 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards.

(d) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers.

(1) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit,

(2) The control device manufacturer's recommended maintenance procedures are followed, and

(3) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed.

(e) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard;

(2) The manufacturer's recommended maintenance procedures are followed for each control device; and

(3) A performance test is conducted on each affected facility at least once every 5 calendar years.

(f) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section.

(1) Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.

(i) Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Each observer determining the presence of visible emissions must meet the training requirements specified in § 2.3 of Method 22 of appendix A-7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of this part, performance test must be conducted within 45 operating days.

(ii) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(iii) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

(2) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15

seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. For reference purposes in preparing the monitoring plan, *see* OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.

(g) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section.

(1) The COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(2) The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section.

(i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For 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.

(ii) The owner or operator 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.

(iii) The owner or operator 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.

(iv) 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.

(v) The owner or operator 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.

(h) The owner or operator of each affected coal truck dump operation that commenced construction, reconstruction, or modification after April 28, 2008, must meet the requirements specified in paragraphs (h)(1) through (3) of this section.

(1) Conduct an initial performance test using Method 9 of appendix A-4 of this part according to the requirements in paragraphs (h)(1)(i) and(ii).

(i) Opacity readings shall be taken during the duration of three separate truck dump events. Each truck dump event commences when the truck bed begins to elevate and concludes when the truck bed returns to a horizontal position.

(ii) Compliance with the applicable opacity limit is determined by averaging all 15-second opacity readings made during the duration of three separate truck dump events.

(2) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(3) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

Back to Top

§ 60.256 Continuous monitoring requirements.

(a) The owner or operator of each affected facility constructed, reconstructed, or modified on or before April 28, 2008, must meet the monitoring requirements specified in paragraphs (a)(1) and (2) of this section, as applicable to the affected facility.

(1) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(i) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(ii) For affected facilities that use wet scrubber emission control equipment:

(A) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(B) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator shall have discretion to grant requests for approval of alternative monitoring locations.

(2) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b).

(b) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent.

(1) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section.

(2) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section.

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply flow rate.

(iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design pH.

(iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(3) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(c) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section.

(1) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall 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).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator 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.

(v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section.

(vi) Once per quarter, the owner or operator 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 (c)(2) of this section.

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator 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 (c)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow the owner and operator 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.

(3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator 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:

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective fabric filter compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the PM emissions.

Back to Top

§ 60.257 Test methods and procedures.

(a) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section.

(1) Method 9 of appendix A-4 of this part and the procedures in § 60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii).

(i) The duration of the Method 9 of appendix A-4 of this part performance test shall be 1 hour (ten 6-minute averages).

(ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A-4 of this part performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.

(2) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used.

(i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.

(ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.

(iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.

(3) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met.

(i) No more than three emissions points may be read concurrently.

(ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point.

(b) The owner or operator must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emissions standards specified in § 60.252 according to the requirements in § 60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section.

(1) Method 1 or 1A of appendix A-4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(2) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-4 of this part shall be used to determine the volumetric flow rate of the stack gas.

(3) Method 3, 3A, or 3B of appendix A-4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses (incorporated by reference— *see* § 60.17) as an alternative to Method 3B of appendix A-2 of this part.

(4) Method 4 of appendix A-4 of this part shall be used to determine the moisture content of the stack gas.

(5) Method 5, 5B or 5D of appendix A-4 of this part or Method 17 of appendix A-7 of this part shall be used to determine the PM concentration as follows:

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test.

(ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(iv) Method 5D of appendix A-4 of this part shall be used for positive pressure fabric filters and other similar applications (*e.g.*, stub stacks and roof vents).

(v) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 ° C (320 ° F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(6) Method 6, 6A, or 6C of appendix A-4 of this part shall be used to determine the SO_2 concentration. A minimum of three valid test runs are needed to comprise an SO_2 performance test.

(7) Method 7 or 7E of appendix A-4 of this part shall be used to determine the NO_X concentration. A minimum of three valid test runs are needed to comprise an NO_X performance test.

(8) Method 10 of appendix A-4 of this part shall be used to determine the CO concentration. A minimum of three valid test runs are needed to comprise a CO performance test. CO performance tests are conducted concurrently (or within a 60-minute period) with NO_X performance tests.

Back to Top

§ 60.258 Reporting and recordkeeping.

(a) The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following:

(1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted.

(2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.

(3) The amount and type of coal processed each calendar month.

(4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.

(5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted.

(6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the logbook. Any actions, *e.g.* objections, to the plan and any actions relative to the alternative control measures, *e.g.* approvals, shall be noted in the logbook as well.

(7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output;

(ii) 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 settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm.

(8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted.

(9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid.

(10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable.

(b) For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow:

(1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test.

(2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test.

(3) All 6-minute average opacities that exceed the applicable standard.

(c) The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical.

(d) After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.* For performance tests that cannot be entered into WebFIRE (*i.e.*, Method 9 of appendix A-4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711.

Back to Top

GENERAL PROVISIONS

Link to 40 CFR 63, Subpart A - General Provisions

Back to Top

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS.

Contents

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?
§ 63.9981 Am I subject to this subpart?
§ 63.9982 What is the affected source of this subpart?
§ 63.9983 Are any EGUs not subject to this subpart?
§ 63.9984 When do I have to comply with this subpart?
§ 63.9985 What is a new EGU?

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?
§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?
§ 63.10001 Affirmative defense for exceedance of emission limit during malfunction.

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?
§ 63.10006 When must I conduct subsequent performance tests or tune-ups?
§ 63.10007 What methods and other procedures must I use for the performance tests?
§ 63.10008 [Reserved]
§ 63.10009 May I use emissions averaging to comply with this subpart?
§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?
§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?
§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?
§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?
§ 63.10031 What reports must I submit and when?
§ 63.10032 What records must I keep?
§ 63.10033 In what form and how long must I keep my records?

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?
§ 63.10041 Who implements and enforces this subpart?
§ 63.10042 What definitions apply to this subpart?

Tables to Subpart UUUUU of Part 63

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs
Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs
Table 3 to Subpart UUUUU of Part 63—Work Practice Standards
Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs
Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS.

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits
Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance
Table 8 to Subpart UUUUU of Part 63—Reporting Requirements
Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU
Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions
Appendix B to Subpart UUUUU of Part 63—-HCl and HF Monitoring Provisions

Source: 77 FR 9464, Feb. 16, 2012, unless otherwise noted.

Back to Top

What This Subpart Covers

Back to Top

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

Back to Top

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

Back to Top

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.
  (1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in § 63.10042, within a subcategory.
  (2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in § 63.10042.
(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.
(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after May 3, 2011.
(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change in process (e.g., fuel or utilization) is considered to be an existing source under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

Back to Top

§ 63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.
(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).
(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

Back to Top

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).
(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.
(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.
(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.
(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.
(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

Back to Top

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.
  (1) An EGU that commenced construction after May 3, 2011.
  (2) An EGU that commenced reconstruction after May 3, 2011.
(b) [Reserved]
[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

Back to Top

Emission Limitations and Work Practice Standards

Back to Top

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.
  (1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and
  (2) EGUs designed for low rank virgin coal.
(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.
  (1) Continental liquid oil-fired EGUs
  (2) Non-continental liquid oil-fired EGUs,
  (3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

Back to Top

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.
   (1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.
   (2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your EGU:
   (1) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the unit; and
   (2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with § 63.10000(b).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

Back to Top

General Compliance Requirements

Back to Top

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c) (1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.
   (i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:
      (A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and
      (B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.
   (ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.
   (iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but you must comply with the performance tune-up work practice requirements in Table 3.

(d) (1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this

chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (e.g., if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See § 63.10010(a) for further details. For PM CPMS installations, follow the procedures in § 63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distribution system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR Part 60, Subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met

the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h) (1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i) (1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

Back to Top

§ 63.10001 Affirmative defense for exceedance of emission limit during malfunction.

In response to an action to enforce the standards set forth in § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:
  (1) The excess emissions:
    (i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and
    (ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and
    (iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and
    (iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and
  (2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and
  (3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and
  (4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
  (5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and
  (6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and
  (7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and
  (8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and
  (9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

Back to Top

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in § 63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.* , an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements

of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: For this calculation, the term E_{hj} in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups*. All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this

requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in $\mu g/m^3$ (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (*i.e.* , either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or
(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) *Liquid-oil fuel moisture measurement.* If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.
(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or
(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or
(3) Obtain and maintain a fuel moisture certification from your fuel supplier.
(4) Use one of the following methods to determine fuel moisture content:
(i) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or
(ii) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1.
(iii) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or
(iv) ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.
(5) Use one of the following methods to obtain fuel moisture samples:
(i) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or
(ii) ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.
(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must
(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or
(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

Back to Top

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:
(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).
(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct

Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, § 63.10007, and § 63.10000(c), except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in § 63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013]

Back to Top

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO_2 , or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data for all nonexempt unit operating conditions (see § 63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (µg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2 , 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP

metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2 , HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013]

Back to Top

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO_2 , HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory are equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Rmm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Rmt_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Rmm_i\right]_p\right] + \sum_{i=1}^{m} Rmt_i} \quad (Eq.\ 1a)$$

View or download PDF

Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

$Herm_i$ = Hourly emissions rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm_i = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAERm = \frac{[\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Herm_i \times Smm_i \times Cfm_i)]_p] + \Sigma_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{[\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n} Smm_i \times Cfm_i]_p] + \Sigma_{i=1}^{m} Smt_i \times Cft_i} \quad (Eq.\ 1b)$$

View or download PDF

Where:

variables with similar names share the descriptions for Equation 1a,

Smm_i = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt_i = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Her_i \times Rm_i)]_p + \Sigma_{i=1}^{m}(Ter_i \times Rt_i)}{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Rm_i)]_p + \Sigma_{i=1}^{m} Rt_i} \quad (Eq.\ 2a)$$

View or download PDF

Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \Sigma_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \Sigma_{i=1}^{m} St_i \times Cft_i} \quad (Eq.\ 2b)$$

View or download PDF

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m}Rt_i} \quad (Eq.3a)$$

View or download PDF

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}St_i \times Cft_i} \quad (Eq.3b)$$

View or download PDF

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO_2 , HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:
   (1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or
   (2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.
   (1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2 , HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.
   (2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2 , HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (g)(1) through (2) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.
   (1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.
   (2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2 , HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013]

Back to Top

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f) (1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.* , period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of

the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14 °C (320° ± 25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1) (i) Install and certify your HAP metals CEMS according to the procedures and requirements in your approved site-specific test plan as required in § 63.7(e). The reportable measurement output from the

HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013]

Back to Top

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with Table 4 to this subpart, § 63.10007, and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.* , tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c) (1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to § 63.10030(e).

(f) (1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.* , the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

Back to Top

Continuous Compliance Requirements

Back to Top

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

Back to Top

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2 , PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2 , O_2 , or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.\ 8)$$

View or download PDF

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq.\ 9)$$

View or download PDF

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_X . This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_X and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

(f) You must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must keep records as specified in § 63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in § 63.10031 concerning activities and periods of startup and shutdown.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013]

Back to Top

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

Back to Top

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM

CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) For an existing EGU, determine your operating limit based on the highest 1-hour average PM CPMS output value recorded during the performance test.

(2) For a new EGU, determine your operating limit as follows.

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average (*x*) in milliamps, and the average of your corresponding three PM compliance test runs (*y*), using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

View or download PDF

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

$$R = \frac{y}{(x - z)} \qquad \text{(Eq. 11)}$$

View or download PDF

Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,

y = the three run average PM lb/MWh,

x = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_L = z + \frac{(0.75 \times L)}{R} \quad \text{(Eq. 12)}$$

View or download PDF

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,
L = your source PM emissions limit in lb/MWh,
z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and
R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \quad \text{(Eq. 13)}$$

View or download PDF

Where:

X_i = the PM CPMS data points for all runs i,
n = the number of data points, and
O_h = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013]

Back to Top

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.
(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.
(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.
(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.
  (1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.
  (2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.
  (3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.
  (4) Identification of whether you plan to demonstrate compliance by emissions averaging.
  (5) A signed certification that you have met all applicable emission limits and work practice standards.
  (6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.
  (7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following:
    (i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(b), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.
    (ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:
      (A) "This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance." and
      (B) "No secondary materials that are solid waste were combusted in any affected unit."

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013]

Back to Top

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.
(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.
(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.
(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.
(1) The information required by the summary report located in 63.10(e)(3)(vi).
(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.
(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.
(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 (or 48) months and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in § 63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority,

you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO_2 , PM, HCl, HF, and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in § 63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and § 63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under § 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

Back to Top

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).
(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.
(1) Records described in § 63.10(b)(2)(vi) through (xi).
(2) Previous (*i.e.* , superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).
(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).
(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.
(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.
(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.
(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.* , process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

Back to Top

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Back to Top

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

Back to Top

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.
   (1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).
   (2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in § 63.2.
   (3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.
   (4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

Back to Top

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to,

coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product 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 with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric 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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO_2 in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the 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 output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), 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 or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

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. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 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.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use).

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Unit designed for coal ≥ 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards

developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23405, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013]

Back to Top

Tables to Subpart UUUUU of Part 63

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS.

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh [4] 9.0E-2 lb/MWh [5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	4.0E-1 lb/MWh	SO_2CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <[1/2]the standard.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	2.0E-1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be $<^{1/2}$the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03 [2]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output.

[78 FR 24087, Apr. 24, 2013]

Back to Top

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits: [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
1. Coal-fired unit not low rank virgin coal	Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [3]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [3]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh.	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [3]or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2; the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 [3]or Method 320, sample for a minimum of 1 hour.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [3]or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh.	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh.	
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2; the standard.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 [3]or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 [3]or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals	Collect a minimum of 3 dscm per run.	
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh.	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh.	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh.	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03 [3]or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1]For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2]Gross electric output.
[3]Incorporated by reference, see § 63.14.
[4]You may not use the alternate SO_2limit if your EGU does not have some form of FGD system and SO_2CEMS installed.
[77 FR 23405, Apr. 19, 2012]

Back to Top

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in §§ 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry

If your EGU is . . .	You must meet the following . . .
	scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

Back to Top

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

As stated in § 63.9991, you must comply with the applicable operating limits:

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS for an existing EGU	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).
2. PM CPMS for a new EGU	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

[78 FR 24090, Apr. 24, 2013]

Back to Top

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [1]

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS.

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2]. . .
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A-3 to part 60 of this chapter.
			For positive pressure fabric filters, Method 5D at Appendix A-3 to part 60 of this chapter for filterable PM emissions.
			Note that the Method 5 front half temperature shall be 160 ° ± 14 °C (320 ° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2]. . .
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at Appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2]. . .
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at Appendix A-8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348-03 [3]with (1) additional quality assurance measures in footnote [4]and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2]. . .
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter, ASTM D6784 [3], or Method 29 at Appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
		Hg CEMS a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2]. . .
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3]or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.*,per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 22.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and §§ 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and § 63.10021(h).
[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

[4] When using ASTM D6348-03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (2) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%)R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100$$

View or download PDF

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24091, Apr. 24, 2013]

Back to Top

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	**And you choose to establish PM CPMS operating limits, you must . . .**	**And . . .**	**Using . . .**	**According to the following procedures . . .**
1. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an existing EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.*,milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
2. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for a new EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.*,milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

[78 FR 24091, Apr. 24, 2013]

Back to Top

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired,	Calculating the results of the testing in units of the applicable

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2	emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with Table 3.

[78 FR 24092, Apr. 24, 2013]

Back to Top

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

As stated in § 63.10031, you must comply with the following requirements for reports:

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	Semiannually according to the requirements in § 63.10031(b).
	c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e)	

Back to Top

Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS.

Citation	Subject	Applies to subpart UUUUU
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (h)(2)-(h)(9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification requirements	Yes, except for the 60-day notification prior to conducting a performance test in § 63.9(d); instead use a 30-day notification period per § 63.10030(d).
§ 63.10(a), (b)(1), (c), (d)(1)-(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.

Citation	Subject	Applies to subpart UUUUU
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)-(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3),and (d)(3)-(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

[78 FR 24092, Apr. 24, 2013]

Back to Top

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account

for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is "in control". However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on "cold standby" and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (*i.e.* , sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg ($Hg^{0,}$ CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST-Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (*i.e.* , low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

FIGURE A-1. TYPICAL MERCURY CEMS

View or download PDF

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™ , quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^{0} converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be

designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (e.g., NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (*i.e.* , a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 µg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 µg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.*, the weight percentage) from at least three representative fuel samples, together with other available information, including, but not

limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 µg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 µg/scm; or the next highest multiple of 10 µg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.,* lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.,* in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.,* lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.9984(f).

4.1.1 *Hg CEMS.* Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.,* resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of

the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1. The SIE must either meet the main performance specification or the alternative specification in Table A-1. (Note: This test is not required if the CEMS does not have a converter).

Table A-1—Required Certification Tests and Performance Specifications for Hg CEMS

For this required certification test . . .	**The main performance specification [1]is . . .**	**The alternate performance specification [1]is . . .**	**And the conditions of the alternate specification are . . .**
7-day calibration error test [2]	$\lvert R - A \rvert \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days	$\lvert R - A \rvert \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check [3]	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high)	$\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check [4]	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level	$\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm**	$RM_{avg} < 5.0$ µg/scm.
Cycle time test [2]	15 minutes.[5]		

[1] Note that $\lvert R - A \rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg}, \rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2] Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.

[3] Use elemental Hg standards.

[4] Use oxidized Hg standards. Not required if the CEMS does not have a converter.

[5] Stability criteria—Readings change by <2.0% of span*or*by ≤0.5 µg/scm, for 2 minutes.

** Note that $\lvert RM_{avg} - C_{avg} \rvert$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between $RM_{avg}$and C_{avg}can be either + or −.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60. When Method 29 or ASTM D6784-02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤ 1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} x100 \quad \text{(Eq. A-1)}$$

View or download PDF

Where:

RD = Relative deviation between the Hg concentrations of samples "a" and "b" (percent)

C_a = Hg concentration of Hg sample "a" (µg/dscm)

C_b = Hg concentration of Hg sample "b" (µg/dscm)

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784-02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 "The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤ 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤ 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems* . Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters". A maximum of three consecutive exemptions for

this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A-2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.*, once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A-2—On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	**At this frequency . . .**	**With these qualifications and exceptions . . .**	**Acceptance criteria . . .**
Calibration error test	Daily	• Use either a mid- or high-level gas	$\lvert R-A \rvert \leq 5.0\%$ of span value. *or* $\lvert R-A \rvert \leq 1.0$ µg/scm.
		• Use either elemental or oxidized Hg	
		• Calibrations are not required when the unit is not in operation	
Single-level system integrity check	Weekly [1]	• Required only for systems with converters	$\lvert R-A_{avg} \rvert \leq 10.0\%$ of the reference gas value. *or* $\lvert R-A_{avg} \rvert \leq 0.8$ µg/scm.
		• Use oxidized Hg—either mid- or high-level	

Perform this type of QA test . . .	**At this frequency . . .**	**With these qualifications and exceptions . . .**	**Acceptance criteria . . .**
		• Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg	
Linearity check *or* 3-level system integrity check	Quarterly [3]	• Required in each "QA operating quarter" [2]—and no less than once every 4 calendar quarters	$\|R-A_{avg}\| \leq 10.0\%$ of the reference gas value, at each calibration gas level. *or* $\|R-A_{avg}\| \leq 0.8$ µg/scm.
		• 168 operating hour grace period available	
		• Use elemental Hg for linearity check	
		• Use oxidized Hg for system integrity check	
		• For system integrity check, CEMS must have a converter	
RATA	Annual [4]	• Test deadline may be extended for "non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test	20.0% RA. *or* $\|RM_{avg}-C_{avg}\| \leq 1.0$ µg/scm, *if* $RM_{avg} < 5.0$ µg/scm.
		• 720 operating hour grace period available	

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.*, once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.*, flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19-19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

View or download PDF

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf,

C_h = Hourly average Hg concentration, wet basis (µg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(Note: Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \qquad \text{(Equation A-3)}$$

View or download PDF

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf.

C_h = Hourly average Hg concentration, dry basis (µg/dscm).

Q_h = Stack gas volumetric flow rate for the hour (scfh)

(Note: Use unadjusted flow rate values; bias adjustment is not required).

B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2 O/100)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\, 10^3 \qquad \text{(Equation A-4)}$$

View or download PDF

Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh).

M_h = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).

$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).

10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A-5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

View or download PDF

Where:

$_o$ = Hg emission rate for the averaging period (lb/GWh).

E_{cho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A-4 of this section (lb/GWh).

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters.

(*Note:* Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.*, flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the

applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO_2* or O_2) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO_2 or O_2 concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also submit the monitoring plan information in § 75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.* , calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, e.g., under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.9.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23408, Apr. 19, 2012; 78 FR 24093, Apr. 24, 2013]

Back to Top

Appendix B to Subpart UUUUU of Part 63—-HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and § 63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (

Please Note: EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (*i.e.* , independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010) "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy" (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be $70\% \leq R \leq 130\%$; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100 \qquad \text{(Eq. B-1)}$$

View or download PDF

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation* .

5.3.1 *Out-of-Control Periods* . A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods* . For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 *Conditional Data Validation* > For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8} .

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, use Equation A-4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A-4 by 10^3 .

9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e*, flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.*, CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.*, lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO_2 or O_2 concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.*, calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification,

quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in § 75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (*i.e.* , initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2-4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24094, Apr. 24, 2013]

Back to Top

Back to Top

NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

Link to 40 CFR 63, Subpart ZZZZ

Back to Top

ATTACHMENTS
(INCLUDED FOR CONVENIENCE)

The following attachments are included for convenient reference:

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

Back to Top

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_2 NO_X TRS H_2S 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 [1]: _____

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown ..... ____ b. Control equipment problems ..... ____ c. Process problems ..... ____ d. Other known causes ..... ____ e. Unknown causes ..... ____ 2. Total duration of excess emissions ..... ____ 3. Total duration of excess emissions x (100) / [Total source operating time] ..... ____ %[2]	1. CMS downtime in reporting period due to: a. Monitor equipment malfunctions ..... ____ b. Non-Monitor equipment malfunctions ..... ____ c. Quality assurance calibration ..... ____ d. Other known causes ..... ____ e. Unknown causes ..... ____ 2. Total CMS Downtime ..... ____ 3. [Total CMS Downtime] x (100) / [Total source operating time] ..... ____ %[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ *Date*: _____

Title: _____

Back to Top

TABLE H

PERMIT HISTORY

This permit history summarizes primarily projects issued after project number 016-AV. For previously issued projects, also refer to the Appendix H-1's referenced in Permit Nos. 1050233-001-AV and 1050233-016-AV posted on the web site.

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
001	260 MW Coal Gasification Combined Cycle CT No. 1	PA 92-32	11/29/1993	N/A	Conditions of Certification
001	260 MW Coal Gasification Combined Cycle CT No. 1	PSD-FL-194	02/24/1994	06/01/1996	Initial Construction
009 & 010	Simple Cycle Turbine No. 2 & 3	PSD-FL-263	10/08/1999	10/31/2002	New Unit Construction
All	Initial Title V Permit	1050233-001-AV	01/01/2000	12/31/2004	Initial Title V Permit
001	PSD revision to add Petcoke	1050233-002-AC PSD-FL-194C	12/14/1999	12/14/2004	PSD Revision
	Withdrawn	1050233-003-AV	n/a	n/a	Title V Revision
001	PSD Mod. To permanently authorize Petcoke	1050233-004-AC PSD-FL-194E	11/17/2000	3/31/2001	PSD Revision
001, 009, 010	PSD Mod. / minor revisions	1050233-005 PSD-FL-194G	06/20/2001	12/31/2001	Construction mod.
	Withdrawn	1050233-006-AV	n/a	n/a	Title V Revision
001	260 MW Coal Gasification Combined Cycle CT No. 1	1050233-007-AC PSD-FL-194F psd-FL-263A	02/05/2002	n/a	PSD Mod.
001, 006	Revision	1050233-008-AV	09/12/2001	12/31/2004	Title V Revision
001	Revision	1050233-009-AV	11/08/2001	12/31/2001	Title V Revision
001	260 MW Coal Gasification Combined Cycle CT No. 1	1050233-010-AC	10/21/2001	10/21/2006	Construction (mod.)
005	Correction	1050233-011-AV	05/14/2002	12/31/2004	Admin. Correction
009, 010	Incorporation of Units 009 and 010	1050233-012-AV	06/23/2003	12/31/2004	Title V Revision
001	260 MW Coal Gasification Combined Cycle CT No. 1: Biomass Test Burn - Bahia Grass	1050233-013-AC	11/25/2003	04/30/2004	One Time Test Burn
	Withdrawn	1050233-014-AV	n/a	n/a	Title V Revision
	Withdrawn	1050233-015-AC	n/a	n/a	Minor AC Revision
All	Facility	1050233-016-AV	01/01/2005	12/31/2009	Renewal (1st)
004	Sulfuric Acid Plant: Cold Gas Cleanup System, MDEA Chiller	1050233-017-AC	11/09/2004	12/31/2005	Construction

TABLE H
PERMIT HISTORY

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
011 & 012	PPS Unit Nos. 4 & 5	1050233-018-AC/ PSD-FL-363	04/28/2006	10/01/2008	Construction
001, 004, 005 & 006	PPS Unit No. 1 Petcoke Test Burn	1050233-019-AC	11/07/2006	11/09/2007	Construction (mod.)
	630 MW IGCC Unit No. 6	1050233-020-AC	Withdrawn on 10/08/2007	NA	Construction
001, 004, 005 & 006	PPS Unit No. 1 - 85% Petcoke Modification	1050233-021-AC/ PSD-FL-194H	06/26/2008	06/01/2009	Construction (mod.)
011 & 012	PPS Unit Nos. 4 & 5 inclusion	1050233-022-AV[1]	08/27/2008	NA	Title V Revision
	CAIR	1050233-023-AC	02/13/2009	NA	Title V Revision (CAIR)
	CAMR	1050233-024-AV	Withdrawn	NA	Title V Revision (CAMR)
001, 004, 005 & 006	Extension of 1050233-021-AC/ PSD194H	1050233-025-AC	04/16/2009	06/30/2010	Construction (mod.)
All	Facility	1050233-026-AV	01/01/2010	12/31/2014	Title V Renewal (2nd)
	HTSC/CCS Demonstration Project	1050233-027-AC	11/17/2011	12/31/2015	Construction
All	Natural gas replacement of fuel oil in Unit 1	1050233-028-AV	12/11/2012	12/31/1014	Title V Revision
Unit 1 (001 to 007)	Clean permit for Unit 1, replacing fuel oil with natural gas	1050233-029-AC PSD-FL-194J	11/26/2012	12/31/2013	Construction Permit Revision
	Withdrawn	1050233-030-AC	n/a	n/a	
	Withdrawn	1050233-031-AV	n/a	n/a	Title V Revision
009, 010, 013, 014	Revise NO_X emission reporting	1050233-032-AC	11/26/2012	12/31/2013	Construction
015*	Removal of CCS system	1050233-033-AC	09/26/2012	N/A	Admin Correction
009, 010, 013, 014	Convert Units 3 and 4 to combined cycle operation	1050233-034-AC PSD-FL-421	05/15/2013	01/01/2016	Construction
005	Removal of VE testing	1050233-035-AC PSD-FL-194K	09/10/2013	12/31/2014	Construction Permit Revision
005	Revision to incorporate 035-AC	1050233-036-AV	10/14/2013	12/31/2014	Title V revision
001, 004	Sulfuric Acid Plant Gearbox Compressor Project	1050233-037-AC	01/30/2014	n/a	Letter of Authorization
	Withdrawn	1050233-038-AC	n/a	n/a	Minor Revision
All	Title V Renewal	1050233-039-AV	01/01/2015	12/31/2019	Title V Renewal (3rd)

Back to Top