FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION
SOUTH DISTRICT
P.O. BOX 2549
FORT MYERS, FL 33902-2549

RICK SCOTT
GOVERNOR

CARLOS LOPEZ-CANTERA
LT. GOVERNOR

HERSCHEL T. VINYARD JR.
SECRETARY

Electronic Mail – Received Receipt Requested

Okeelanta Corporation
New Hope Power Company
8001 U.S. Highway 27 South
South Bay, Florida 33493

Responsible Official:
Jose Gonzalez, Vice president of Industrial Operations

Permit No. 0990005-038-AV
Okeelanta Corporation
Facility ID No. 0990005
New Hope Power Company
Facility ID No. 0990332
Title V Air Operation Permit Revision
Palm Beach County, Florida

Re: Permit No. 0990005-038-AV
Title V Permit Revision/Renewal

Dear Mr. Gonzalez:

Enclosed is the draft/proposed permit package to revise the Title V air operation permit for the sugar mill, refinery and transsshipment facilities operated by the Okeelanta Corporation as well as the cogeneration plant operated by New Hope Power Company. The existing facility is located in Palm Beach County at 8001 U.S. Highway 27 South, South Bay, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

The permit package includes the following documents:

- The Statement of Basis, which summarizes the facility, the equipment, the primary rule applicability, and the changes since the last Title V renewal.
- The revised draft/proposed Title V air operation permit, which includes the specific permit conditions that regulate the emissions units covered by the proposed project.
- The Written Notice of Intent to Issue Air Permit provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the draft/proposed permit; the process for filing a petition for an administrative hearing; and the availability of mediation.
- The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The Public Notice of Intent to Issue Title V Air Permit must be published as soon as possible and the proof of publication must be provided to the Department within seven days of the date of publication. Because this permit is being processed as a combined draft/proposed permit in order to reduce processing time, a duplicate copy of the proof of publication must also be transmitted by electronic mail within seven days of the date of publication to Ms. Natasha Hazziez at EPA Region 4 at the following address: hazziez.natasha@epa.gov.

If you have any questions, please contact the Project Engineer, Carter B. Endsley, P.E., by telephone at (239) 344-5637 or by email at Carter.Endsley@dep.state.fl.us

Executed in Fort Myers, Florida.

Jon M. Iglehart
Director of District Management

JMI/CBE/se

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Title V Air Operation Permit by:

Okeelanta Corporation
New Hope Power Company
21250 U.S. Highway 27 South
South Bay, Florida 33493

Responsible Official:
Jose Gonzalez, Vice president of Industrial Operations

Permit No. 0990005-038-AV
Okeelanta Corporation
Facility ID No. 0990005
New Hope Power Company
Facility ID No. 0990332
Title V Air Operation Permit Revision
Palm Beach County, Florida

Facility Location: Okeelanta Corporation operates the Okeelanta Sugar Mill, Refinery, and Trans-shipment Facility, as well as the cogeneration plant operated by New Hope Power Company. The Facility is located in Palm Beach County at 22150 U.S. Highway 27 South, South Bay, Florida.

Project: The purpose of this project is to revise the Title V air operation permit No. 0990005-034-AV to incorporate the changes made in air construction permits numbers 0990005-035-AC and 0990005-037-AC, which authorized the addition of a baghouse to the sugar refinery's Bulk Load-Out Operation (EU ID 034) and addition of four sugar packaging lines (Numbers 16, 17, 18, and 19) with a baghouse to be located in Warehouse Number 3. Details of the project are provided in the application and the referenced Statement of Basis.

Permitting Authority: Applications for Title V air operation permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, 62-213 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and a Title V air operation permit is required to operate the facility. The Office of Permitting and Compliance in the Division of Air Resource Management is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 2295 Victoria Avenue, Ste. 364, Fort Myers, Florida. The Permitting Authority's mailing address is: P.O. Box 2549, Fort Myers, Florida 33902-2549. The Permitting Authority's telephone number is (239) 344-5600.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the address indicated above for the Permitting Authority. The complete project file includes the draft/proposed permit, the Statement of Basis, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may view the draft/proposed permit by visiting the following website: http://www.dep.state.fl.us/air/emission/apds/default.asp and entering the permit number shown above. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue a Title V air operation permit revision to the applicant for the project described above. The applicant has provided reasonable assurance that continued operation of the existing equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a final permit in accordance with the conditions of the draft/proposed permit unless a response received in accordance with the following procedures results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the draft/proposed Title V air operation permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly (FAW). If a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received written comments or comments received at a public meeting result in a significant change to the draft/proposed permit, the Permitting Authority shall issue a revised draft/proposed permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection. For additional information, contact the Permitting Authority at the above address or phone number.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this written notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this written notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. A petition for administrative hearing must contain the information set forth below and must be filed (received) with the Agency Clerk in the Office of General Counsel, 3900 Commonwealth Boulevard, MS 35, Tallahassee, Florida 32399-3000, Agency.Clerk@dep.state.fl.us, before the deadline. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, any email address, telephone number and any facsimile number of the petitioner; the name, address, any email address, telephone number, and any facsimile number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

Mediation: Mediation is not available in this proceeding.

EPA Review: EPA has agreed to treat the draft/proposed Title V air operation permit as a proposed Title V air operation permit and to perform its 45-day review provided by the law and regulations concurrently with the public comment period, provided that the applicant also transmits an electronic copy of the required proof of publication directly to EPA at the following email address: hazziez.natasha@epa.gov. Although EPA's 45-day review period will be performed concurrently with the public comment period, the deadline for submitting a citizen petition to object to the EPA Administrator will be determined as if EPA's 45-day review period is performed after the public comment period has ended. The final Title V air operation permit will be issued after the conclusion of the 45-day EPA review period so long as no adverse comments are received that result in a different decision or significant change of terms or conditions. The status regarding EPA's 45–day review of this project and the deadline for submitting a citizen petition can be found at the following website address: http://www.epa.gov/region4/air/permits/florida.htm.

Objections: Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 days of the expiration of the Administrator's 45-day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to the issuance of any Title V air operation permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30-day public comment period provided in the Public Notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460. For more information regarding EPA review and objections, visit EPA's Region 4 web site at http://www.epa.gov/region4/air/permits/florida.htm.

Executed in Fort Myers, Florida.

Jon M. Iglehart
Director of
District Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this written notice of Intent to Issue Title V Air Operation Permit Revision (including the Public Notice, the Statement of Basis, and the draft/proposed permit), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Jose Gonzalez, NHPC: Jose_Gonzalez@floridacrystals.com
Mr. Matthew Capone, NHPC: matthew_capone@floridacrystals.com
Mr. David A. Buff, P.E.: dbuff@golder.com
Mr. Carter B. Endsley, P.E.: carter.endsley@dep.state.fl.us
Mr. James Stormer, Palm Beach County Health Department: james_stormer@doh.state.fl.us
Ms. Cindy Mulkey, DEP Siting: cindy.mulkey@dep.state.fl.us
Ms. Natasha Hazziez, EPA Region 4: hazziez.natasha@epa.gov
Ms. Ana Oquendo, EPA Region 4: oquendo.ana@epa.gov
Ms. Barbara Friday, DEP OPC: barbara.friday@dep.state.fl.us
Ms. Lynn Scearce, DEP OPC: lynn.scearce@dep.state.fl.us

Clerk Stamp

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

Susan Edwards ______ July 8, 2014

Clerk Date

Okeelanta Corporation
Sugar Mill and Refinery

Facility ID No. 0990005

New Hope Power Company
Okeelanta Cogeneration Plant

Facility ID No. 0990332

Palm Beach County

Title V Air Operation Permit Revision

Draft/Proposed Permit No. 0990005-038-AV

(4th Revision to Permit No. 0990005-017-AV)

Permitting Authority:

State of Florida
Department of Environmental Protection
South District Office
Engineering/Permitting Division

2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33902-2549

Telephone: (239) 344-5600
Fax: (850) 412-0590

Compliance Authority:

Palm Beach County
Health Department
800 Clematis Street
Post Office Box 29
West Palm Beach, FL 33402-0029

Telephone: (561) 837-5900
Fax: (561) 837-5295

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DRAFT/PROPOSED

PERMITTEE:

Okeelanta Corporation
New Hope Power Company
8001 U.S. Highway 27 South
South Bay, Florida 33493

Permit No. 0990005-038-AV
Okeelanta Corporation
Facility ID No. 0990005
New Hope Power Company
Facility ID No. 0990332
Title V Air Operation Permit Revision
Palm Beach County, Florida

The purpose of this permitting project is to revise the existing Title V air operation permit No. 0990005-034-AV for the above referenced facility to incorporate minor revisions from air construction permit Nos. 0990005-035-AC (added baghouse to the Bulk Load-out Operation (EU-034) and 0990005-037-AC (added four (4) Sugar Packaging Lines No. 16, 17, 18 and 19 with baghouse, to Warehouse No. 3. The facility is operated by the Okeelanta Corporation (ARMS ID No. 0990005) and the New Hope Power Company (ARMS ID No. 0990332). Okeelanta Corporation operates an existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) and New Hope Power Company operates a cogeneration plant (SIC No. 4911).

The existing facility is located in Palm Beach County at 8001 U.S. Highway 27 South, South Bay, Florida. The map coordinates are UTM Zone 17, 524.90 km East and 2940.10 km North (Latitude 26° 35’ 00” North / Longitude 80° 45’ 00” West).

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

0990005-017-AV Effective Date: July 17, 2010
0990005-032-AV 1st Revision Effective Date: September 11, 2012
0990005-033-AV 2nd Revision Effective Date: October 11, 2012
0990005-034-AV 3rd Revision Effective Date: August 29, 2013
0990005-038-AV 4th Revision Effective Date: *DRAFT*

Renewal Application Due Date: December 3, 2014
Expiration Date: July 16, 2015

DRAFT/PROPOSED

Jon M. Iglehart
Director of
District Management

JMI/CBE/

FACILITY DESCRIPTION

The facility consists of two adjacent plants. Okeelanta Corporation (ARMS ID No. 0990005) operates an existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including sugar packaging and transshipment activities. New Hope Power Company (ARMS ID No. 0990332) operates an existing cogeneration plant that provides process steam for the sugar mill and refinery operations as well as generating electricity for sale to the power grid (SIC 4911). The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs.

The primary sources of air pollution include: Three (3) - 760 million British thermal units per hour (MMBtu/hr) per hour cogeneration boilers; transfer and storage of wood chip and bagasse fuels; distillate oil storage tanks; transfer and storage of sugar; and a paint spray booth. The facility includes other miscellaneous "unregulated" emissions units and activities.

REGULATORY CATEGORIES

- The facility is a major source of hazardous air pollutants.
- The facility does <u>not</u> operate any units subject to the Title IV acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source of air pollution in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility is subject to Chapter 62-17, F.A.C. for power plant site certification because it produces more than 75 MW of steam-generated electrical power. [Site Certification No. PA 04-46]
- Existing units are subject to the following New Source Performance Standards (NSPS) in Part 60 of Title 40, the Code of Federal Regulations (CFR): Subpart A (General Provisions),
- NSPS Part 60, Subpart Da (Electric Utility Steam Generating Units).
- Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A General Provisions.
- Units are subject to 40 CFR 63 Subpart DDDDD-National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. [Rule 62-213.440, F.A.C.] *Appendix SS provides a summary of the applicable requirements for each regulated unit.*
- Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A – General Provisions.

REGULATED POLLUTANTS

Criteria Pollutants

Emissions units at this facility may emit one or more of the following criteria air pollutants: carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM_{10}), volatile organic compounds (VOC) and lead (Pb).

Other Regulated PSD Pollutants

In addition to the above criteria air pollutants, emissions units at this facility may emit one or more of the following PSD pollutants: fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; and mercury (Hg).

Hazardous Air Pollutants

Emissions units at this facility may emit one or more hazardous air pollutants (HAP) as defined in Rule 62-210.200, F.A.C.

SUMMARY OF REGULATED EMISSIONS UNITS

Please refer to the appropriate Permit No., Facility ID No. and Emissions Unit No. on all correspondence, test report submittals, applications, etc.

ARMS ID No. 0990005 - Okeelanta Corporation

EU No.	Emissions Unit Description	Process Area
014	*Boiler No. 16 (DELETED)*	*Sugar Mill and Refinery*
018	Central Vacuum System (listed as insignificant unit)	Transshipment Facility
019	Sugar Packaging Lines 0-9, including 8A and 8B	Transshipment Facility
020	Sugar Grinder/Hopper	Transshipment Facility
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1	Sugar Refinery
022	Central Dust Collection System No. 2 with Roto-clone (No.2) "B" System	Sugar Refinery
023	Cooler No. 1 with Roto-clone No. 3	Sugar Refinery
024	Cooler No. 2 with Roto-clone No. 4	Sugar Refinery
025	Fluidized Bed Dryer/Cooler with Baghouse	Sugar Refinery
030	Sugar Silos Nos. 1, 2, and 3	Transshipment Facility
031	Railcar Sugar Unloading Receiver 1	Transshipment Facility
032	Railcar Sugar Unloading Receiver 2	Transshipment Facility
034	Bulk Load-Out Operation *with baghouse*	Sugar Refinery
035	Transfer Bulk Load-Out Operation	Sugar Refinery
043	Sugar Refinery Alcohol Usage	Sugar Refinery
045	Powdered Sugar Dryer/Cooler, Packaging Line 8A And 8B	Transshipment Facility
046	Powdered Sugar Hopper	Transshipment Facility
047	Sugar Packaging Lines 12 and 13	Transshipment Facility
048	Paint Booth	Okeelanta Shop
049	Sugar Packaging Line 14	Transshipment Facility
054	"A" System - Wet Roto-clone (No. 6)	Sugar Refinery
055	"C" System - Wet Roto-clone (No. 7)	Sugar Refinery
056	Hi-Vac Industrial Vacuum System	Sugar Refinery
059	*Pkg. Lines 16, 17, 18 & 19 with baghouse*	*Warehouse 3*

{Permitting Note: The original sugar mill boilers (EU-001 - EU-013) and Boiler No. 16 (EU-014) have been permanently shutdown.}

ARMS ID No. 0990332 – New Hope Power Company

EU No.	Emissions Unit Description	Process Area
001	Cogeneration Boiler A	Cogeneration Plant
002	Cogeneration Boiler B	Cogeneration Plant
003	Cogeneration Boiler C	Cogeneration Plant
004	Cogeneration Plant - Material Handling and Storage	Cogeneration Plant

Unregulated Emissions Units and/or Activities

ARMS ID No. 0990005 – Okeelanta Corporation

EU No.	Emissions Unit Description	Process Area
015	*Fuel Storage Tank (Deleted)*	*Sugar Mill and Refinery*
016	*Fuel Storage Tank (Deleted)*	*Sugar Mill and Refinery*
017	*Fuel Storage Tank (Deleted)*	*Sugar Mill and Refinery*
033	Sugar Refinery Miscellaneous Support Equipment	Sugar Refinery
036	Shop Operations	Sugar Mill
037	Sugar Mill Boiler House	Sugar Mill
038	Sugarcane Dumping Area	Sugar Mill
039	Sugarcane Processing Facility	Sugar Mill
040	Fuel Tank Farm	Facility
041	Potable Water System	Facility
042	Sewer Plant	Facility
044	Okeelanta Facility - Miscellaneous Unregulated Activities	Okeelanta Facility
050	Transshipment Facility, Miscellaneous Support Equipment	Transshipment Facility
056	Hi-Vac Industrial Vacuum System	Sugar Refinery

Unregulated Emissions Units and/or Activities

ARMS ID No. 0990332 – New Hope Power Company

EU No.	Emissions Unit Description	Process Area
005	Cogeneration Plant - Miscellaneous Support Equipment	Cogeneration Plant

Subjects contained in "Unregulated and Insignificant" emissions units and activities: (Also summarized in Appendix UI in Section 4 of this permit).

Okeelanta Corporation Sugar Mill and Refinery (ARMS ID No. 0990005)

ID No.	EU Description	Activities/Equipment
033	Sugar Refinery Miscellaneous Support Equipment	• Bagging Machines • Bulk Curing, Wet Sugar and Portable Overflow Bins • Centrifugals • De-Sweeteners • Evaporators and Condensers • Large and Small Heaters • Primary and Secondary Filters • Refined Sugar Handling, Storage Silo, and Sugar/Syrup Mixer • Rotex Screens • Silo Scale • Sugar Refinery Process Tanks (Blackwater, Clarifier, Liquor, Melted Sugar Storage, Melter, Mixer, Reactor, Scums, Secondary Treatment, Sweetwater, Syrup Storage Tanks, and Phosphoric Acid Storage and Distribution System • Vacuum Pans with Condenser and non-Condensable Gas Vent • Isopropyl Alcohol Stored in Drums • Powdered Carbon Mixing Room • Refined Sugar Dust Collectors (Vented Inside Building)
036	Shop Activities	• Surface Coating Operations (Non-RACT Vehicle Painting) • Diesel Engine – Portable Air Compressor • Vehicle Repair (Body Shop) • Crawlers Repair Shop • Hydraulic Oil, Mineral Spirits, and Waste/Used Oil Storage Tanks • Mechanics' Trucks With Portable Air Compressors (Gasoline Engines) • Portable Pressure Cleaners (Gasoline Engines) • Steam Clean Station • Truck, Trailer, Service Vehicles, Wheel Tractor Repair Shops • Cold Cleaning Devices (parts washer) • Containers for Oil/Grease/Used Oil • Oil/Water Separator/Skimmer Equipment • Portable Welders • Pressurized LPG Tanks • Stationary IC Engines • Vacuum Cleaning Systems • Vehicle Generated Dust • Woodworking and Metal Working Operations
037	Sugar Mill Boiler House	• Boiler Blowdown Pipes & Vents • Boiler Water Chemical Prep Tanks • Boiler Water Dearator and Tank
038	Sugar Mill Cane Dumping Area	• Cane Dumping, Handling, and Storage Cane Knives, Shredding, and Conveying • Steam Clean Station • Oil/Water Separator/Skimmer

ID No.	EU Description	Activities/Equipment
039	Sugarcane Processing Facility	• *Bagacillo Cyclone and Handling Systems* • *Batch Mixers (<30 Cu. Ft.)* • *Carbonaceous Fuel Conveying, Handling, and Storage Piles* • *Cold Cleaning Devices (Non-Halogenated Solvent)* • *Containers For Oils/Wax/Grease* • *Cooling Water Towers, Spray Ponds and Canals* • *Covered Conveyors/Drop Points* • *Diesel, Gasoline, Fuel Oil, Kerosene, Lube Oil, Waste and Used Oil Tanks* • *Electric Ovens For Drying* • *Emergency Generators* • *Gear Boxes, Reducers Vents* • *Ground Water Remediation Stripping Tower* • *Handling Of Raw Sugar* • *Industrial Waste Water Tanks (Non-MACT)* • *Molasses Storage Tanks* • *Mud Ponds* • *Oil/Water Separator/Skimmer Equipment* • *Painting Operations* • *Portable Diesel Air Compressors* • *Portable Electric Generators* • *Portable Welders* • *Pressurized LPG Tanks* • *Process Water Filtration Intake Screens* • *Process Wide Flanges and Valves* • *Pump Operations* • *Scrubber Water Ponds and Troughs* • *Stationary Internal Combustion Engines (General)* • *Vacuum Cleaning Systems* • *Vehicle Generated Dust* • *Vents From Hydraulic/Lube Oil Reservoirs* • *Woodworking and Metal Working Operations* • *Centrifugals With Mixers* • *Crystallizers/Receivers* • *Evaporator Cleaning Operations* • *Evaporators (W/ Non-Condensable Gas Vent)* • *Juice Heaters* • *Mud Filter Condensers Vacuum Pumps* • ***Process Tanks (Batch, Clarified Juice, Coagulant Mix, Flash, Liming, Mingler, Mixer, Mud Mixing, Pan Feed, Magma, Mud Waste, Muriatic, Sugar Receiver, and Syrup Storage)*** • ***Isopropyl alcohol stored in drums*** • *Isopropyl alcohol usage in vacuum pans* • *Rotary Vacuum Filters* • *Vacuum Pans with NCG vents, Condensers, And Pumps* • *Lime Storage Silo and Distribution Systems* • *Lime Silo Baghouse (5% Opacity)* • *Diesel Engines for Operation of IWW Pumps*

ID No.	EU Description	Activities/Equipment
		• *Phosphoric Acid Storage and Distribution Systems* • *Sodium Hydroxide Storage and Distribution Systems* • *Mill Crown Wheel Removal Operations* • *Vertical Molasses Crystallizer* • *Cane Mills* • *Cush-cush Screens/Conveyors and DSM Screens* • *Hydrochloric Acid Tanks* • *Mill Turbines with Vents* • *Carbon Slurry Tank* • *Condensate Tank*
040	Facility Fuel Tank Farm	• *Diesel, Gasoline and Oil Tanks* • *Diesel and Gasoline Pumps and Loading Arms* • *Oil/Water Separator/Skimmer Equipment*
041	Facility Potable Water System	• Hydrogen Sulfide Degasifiers • Membrane Cleaning Chemicals and Process Water Discharge Canal • Sulfuric Acid Storage and Distribution Systems • Disinfection System
042	Facility Sewer Plant	• Sewage Treatment Plant • Collection and Distribution Lift Station
044	Okeelanta Facility - Miscellaneous Unregulated Activities	• Forklift and crane operations • Bagasse conveying to cogeneration boilers or biomass storage
050	Transshipment Facility, Miscellaneous Support Equipment	• Containers for Oil/Grease/Ink • Diesel Fire Pump Engine • Diesel Tank • Vehicle Generated Dust • Refined Sugar Dust Collectors (Vented Inside Building) • Portable Vacuum Cleaners • Propane-Fired Water Heaters for Disinfection Process Vessels • Steam Clean Station • Cold Cleaning Devices (Parts Washer)

The following activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

056	*Hi-Vac Industrial Vacuum System*	• *Sugar Mill & Refinery*
053	*Printing Operation*	• *Trans-shipment*

The following emission units have been determined by the Department to be EXEMPT from permitting.

057	*Specialty Sugar Product*	• *300 hp gas-fired package boiler (Refined Sugar Warehouse No. 3)*
058	*Sugar Bin with Dust*	• *(Refined Sugar Warehouse # 3)*

	Collector	
052	*Bulk Transfer Station*	• *Wet Roto-clone No. 5*
051	*Refined Sugar Silo*	• *Baghouse*
029	*Packaging Line 10*	• *Baghouse (Located in Sugar Refinery)*

Exemptions for temporary jaw crushers:

Exemption permit No. 0990005-028-AC (dated June 17, 2011) and permit No. 0990005-031 (dated December 15, 2011) were issued for temporary jaw crushers, operated by third party, for short term operation pertaining to demolishing of the old carpenter shop and three adjacent concrete slabs. This temporary operation has been completed and these exemptions are no longer applicable.

Unless otherwise specified by the permit, the following conditions apply facility-wide to all emission units and activities:

PERMITTING AND COMPLIANCE AUTHORITIES

1. Permitting Authority: All documents related to applications for permits to operate an emissions unit shall be submitted to the Engineering/Permitting Division of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is (239) 344-5600 and the fax number is (850) 412-0590. Copies shall be sent to each agency identified under Compliance Authority.

2. Compliance Authority: The permittee shall submit all compliance related notifications and reports required of this permit to the Air & Waste Section, Division of Environmental Public Health (4th Floor) of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029. The telephone number is (561) 837-5900 and the fax number is (561) 837-5295. Copies of all such documents shall be submitted to the Air Resources Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-2549. The telephone number is (239) 344-5600 and the fax number is (850) 412-0590.

PERMIT APPENDICES

3. Appendices: The appendices identified as Section 4 in the Table of Contents are attached as an enforceable part of this permit unless otherwise indicated.

ANNUAL REPORTS AND FEES

4. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility in accordance with the requirements in Rule 62-210.370, F.A.C. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. (Ref. electronic submission to DEP/Tallahassee as specified in Rule 62-210.370(3), F.A.C.).

5. Annual Emissions Fee Form and Fee: The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm [Rule 62-213.205, F.A.C.]

EMISSIONS AND CONTROLS

6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

7. General VOC and OS Emission Limiting Standards: The permittee shall not store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. Nothing was deemed necessary and ordered on a facility-wide basis. [Rule 62-296.320(1)(a), F.A.C.]

8. General Visible Emissions: Unless otherwise specified by this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. If the presence of uncombined water is the only reason for failure to meet visible emission standards given in this rule, such failure shall not be a violation of this rule. All visible emissions tests performed pursuant to this rule shall be conducted in accordance with EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C. This permit condition does not impose any periodic testing requirement. [Rule 62-296.320(4) (b)1, F.A.C.]

9. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the

outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.; and Permit PSD-FL-333]

10. Unconfined Particulate Emissions: This permit requires the use of fans, filters, pneumatic unloading/loading, ductwork, storage silos and other similar equipment to contain, capture, and/or control particulate matter related to the storage and handling of fuels, raw materials and products. The permittee shall also take the following reasonable precautions to prevent fugitive particulate matter emissions from any activity, including: vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling of fuels, raw materials or products.

    a. Where practicable, enclose or cover conveyor systems.
    b. Minimize drop distances of dry materials when handling.
    c. As necessary, provide wind breaks around material handling equipment.
    d. Where possible, confine abrasive blasting.
    e. As necessary, paving and maintenance of roads, parking areas and yards.
    f. As necessary, use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
    g. As necessary, provide landscape and/or vegetation.
    h. As necessary, remove dust from roads, work areas, parking areas, and other paved areas under the control of the permittee to prevent fugitive dust emissions.
    i. As necessary, apply water or other dust suppressants to control emissions from unpaved roads, yards, and other activities such as road grading, land clearing, and the demolition of buildings.

    [Rules 62-4.070(3) and 62-296.320(4)(c), F.A.C.]

11. Definitions: Unless otherwise specified by permit, startup, shutdown and malfunction are defined as follows.

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

    [Rule 62-210.200(Definitions), F.A.C.]

12. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations that are based on data collected from continuous emissions monitoring systems (CEMS). [Rule 62-210.700(4), F.A.C.]

13. Excess Emissions Allowed: Unless otherwise specified in an emissions unit subsection or Appendices of this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing:

    a. Best operational practices to minimize emissions are adhered to, and

b. The duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period.

Rule 62-210.700, F.A.C., cannot vary any federal NSPS or NESHAP provisions. [Rule 62-210.700(1), F.A.C.]

14. Excess Emissions Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. (Plant Operation - Problems). If requested, a full written report on the malfunctions shall be submitted in a quarterly report. [Rule 62-210.700(6), F.A.C.]

15. 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 (within one working day) notify the Compliance Authority. 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. [Rule 62-4.130, F.A.C.]

ADMINISTRATIVE REQUIREMENTS

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

17. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

18. Reporting to EPA: Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency should be sent to: EPA Region 4 Office; Air, Pesticides & Toxics Management Division; Air and EPCRA Enforcement Branch - Air Enforcement Section; 61 Forsyth Street; Atlanta, Georgia 30303-8960. The telephone number is (404)562-9155 and the fax number is (404) 562-9163.

19. Prevention of Accidental Releases (Section 112(r) of CAA): If and when the facility becomes subject to 112(r), the permittee shall:

    a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038. The telephone: number is (703) 227-7650.

    b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C. [40 CFR 68]

This subsection addresses the following emissions units.

EU No.	Emissions Unit Description (ARMS ID No. 0990332)
001 **002** **003**	**Cogeneration Boilers A (EU-001), B (EU-002) and C (EU-003)**: Each cogeneration boiler is a spreader stoker steam boiler manufactured by Zurn and designed to produce approximately 506,100 pounds per hour of steam at 1500 pounds per square inch, gage (psig) and 975 degrees Fahrenheit (°F). The primary fuel is biomass at a heat input rate of 760 MMBtu/hr, which includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. Auxiliary fuels include natural gas at a heat input rate of 400 MMBtu/hr and distillate oil at a heat input rate of 490 MMBtu/hr. Pollution control equipment includes low-NO_X burners for gas firing, a selective non-catalytic reduction system to reduce nitrogen oxides emissions, and mechanical dust collectors and an electrostatic precipitator to reduce particulate matter emissions. Good operating practices and the efficient combustion of clean, low-sulfur fuels minimizes emissions of CO, SAM, SO_2, and VOC. Exhaust gases exit a stack that is 10 feet in diameter and at least 199 feet tall with a volumetric flow rate of approximately 319,000 actual cubic feet per minute (acfm) at 352° F.

The following describes the primary applicable requirements for the cogeneration boilers.

Prevention of Significant Deterioration (PSD) of Air Quality, Rule 212.400, F.A.C.: Permit No. PSD-FL-196 (as modified) for which the cogeneration boilers were subject to BACT determinations CO, Fl, NO_X, Pb, PM/PM_{10}, SAM, SO_2, and VOC.

Acid Rain: The cogeneration plant is currently classified as a "Qualifying Cogeneration Facility" under 40 CFR Part 72 and is exempt from Acid Rain permitting. However, to maintain the exemption as a qualifying cogeneration facility, total electrical generation may not exceed 219,000 megawatt-electrical-hours (MWe-h) per unit per year based on a 3-year average. It is possible that the cogeneration boilers will later become subject to the Title IV Acid Rain provisions.

National Emission Standards for Hazardous Air Pollutants (NESHAP) - 40 CFR 63, Subpart DDDDD, Industrial, Commercial, and Institutional Boilers and Process Heaters. [Rule 62-213.440, F.A.C.]

- *NSPS Provisions in 40 CFR 60, incorporated by reference in Rule 62-204.800, F.A.C., including*: Subpart A (General Provisions); Subpart Da (Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978) and NSPS Subpart Ea (Applicability for Standards of Performance for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994).

Specific State Regulations: Rule 62-296.405(2), F.A.C. applies to fossil fuel-fired steam generators with more than 250 MMBtu per hour of heat input. Rule 62-296.410, F.A.C. applies to carbonaceous fuel burning equipment. Rule 62-296.570, F.A.C. applies RACT to major VOC- and NOx-emitting facilities.

Compliance Assurance Monitoring (CAM): Rule 62-213.440(1)(b), F.A.C. applies to the particulate matter standards for the cogeneration boilers.

EQUIPMENT SPECIFICATIONS

1. Production Capacity: The cogeneration plant includes a nominal 75 MW steam turbine electrical generator and a nominal 65 MW steam turbine electrical generator. *{Permitting Note: The cogeneration plant has a nominal generating capacity of 140 MW. Therefore, the facility is subject to the power plant site certification requirements of the Department. Subsequent modifications must be made in accordance with appropriate site certification requirements.}* [Permit No. PSD-FL-196P; Rule 62-4.070(3), F.A.C.]

2. Boiler Design: The cogeneration boilers are spreader stoker units designed to fire biomass as the primary fuel with pipeline natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup

and shutdown, when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain an air construction permit before firing any other fuel (including coal) not specifically authorized by this permit.}*

[Permit No. PSD-FL-196P; Rule 62-4.070(3), F.A.C.]

3. Stack: Each cogeneration boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack shall comply with Rule 62-297.310, F.A.C. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-297.310, F.A.C.]

4. Process Monitors: Each cogeneration boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. [Permit No. PSD-FL-196P; Rule 62-4.070(3), F.A.C.]

5. Control Equipment: Each cogeneration boiler shall be equipped with:

   a. Low-NO_X natural gas burners rated for no more than 0.15 lb of NO_X per MMBtu of heat input. Four burners are installed with one in each corner of the boiler. The maximum heat input rate from all four burners is 400 MMBtu per hour.

   b. Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85 percent of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).

   c. An electrostatic precipitator designed for at least 98 percent removal of particulate matter.

   d. A selective non-catalytic reduction system designed for at least 40 percent removal of NO_X.

   The permittee shall abide by the O&M plans for the cogeneration plant control equipment specified in Appendix OM of this permit. [Permit Nos. PSD-FL-196M and PSD-FL-196Q; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

6. Good Combustion Practices: The boiler operators shall follow the procedures for "good combustion practices" identified in Appendix GC of this permit. [Permit No. PSD-FL-196P]

7. Continuous Monitors: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate a COMS to continuously measure and record opacity and CEMS to continuously measure and record emissions of CO, NO_X, CO_2, and SO_2 in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. [Permit No. PSD-FL-196P; NSPS Subpart Da; Rules62-4.070(3) and 62-212.400 (BACT), F.A.C.]

8. Control Equipment O&M Plan: The permittee shall abide by the operation and maintenance (O&M) plans for the cogeneration plant control equipment specified in Appendix OM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS

9. Permitted Capacity: The maximum heat input rate to each cogeneration boiler shall not exceed 760 MMBtu/hr when burning 100 percent biomass, 400 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent distillate oil. The steam production rate of each boiler shall not exceed an average of 506,100 pounds per hour at 1,500 psig and 975°F. The operating hours of the cogeneration boilers are not restricted (8760 hours per year). [Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

10. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized

wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30 percent by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter. The permittee shall abide by the Ash and Fuel Management Plans specified in Appendices AM and FM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

11. Auxiliary Fuel: The cogeneration boilers shall fire only distillate oil and natural gas as auxiliary fuels. The maximum sulfur content of distillate oil is limited to 0.05 percent by weight. In addition to the primary authorized fuels, each boiler may startup on natural gas or distillate oil. The firing of all fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter. The permittee shall abide by the Ash and Fuel Management Plans specified in Appendices AM and FM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

12. Fuel Management Plan: The permittee shall abide by the Fuel Management Plan specified in Appendix FM. [Permit No. PSD-FL-196P]

EMISSION LIMITING STANDARDS

13. Emissions Standards: Unless otherwise specified, the averaging period for an emissions standard is based on the averaging period specified in the applicable test method. Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

Pollutant	Averaging Period	Emissions Standards per Boiler [i]	
		lb/MMBtu	lb/hr
Carbon Monoxide [a]	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides [b]	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide [c]	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity [d]	6-minute block average by COMS and EPA Method 9	≤ 20% opacity, except for one 6-minute block per hour ≤ 27% opacity	
Particulate Matter [e]	3-run test avg.	0.026	19.8
Volatile Organic Compounds [f]	3-run test avg.	0.05	38.0
Mercury [g]	3-run test avg.	5.4×10^{-06}	NA

Pollutant	Averaging Period	Emissions Standards per Boiler [i]	
		lb/MMBtu	lb/hr
Lead and Fluorides[h]	The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.		

a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NO_X monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period.

b. Compliance shall be determined by data collected from the required NO_X CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and the requirements of 40 CFR 60.13, 60.44a, 60.46a, 60.47a, 60.48a, and 60.49a. A boiler-operating day is any day in which any authorized fuel is fired. Each cogeneration boiler is also subject to Rule 62-296.405(2)(d), F.A.C. and 40 CFR 60.44a, which limits NO_X emissions to 0.20 lb/MMBtu for gaseous fuels, 0.30 lb/MMBtu for liquid fuels, and 0.60 lb/MMBtu for solid fuels. Compliance with the BACT standard ensures compliance with these standards.

c. Compliance with the SO_2 standards shall be determined by data collected from the required SO_2 CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO_2 hourly averages shall not be excluded from any compliance average. Each cogeneration boiler is also subject to Rule 62-296.405(2)(c), F.A.C. and 40 CFR 60.43a(d)(2), which limits SO_2 emissions to 1.20 lb/MMBtu for solid fuels and 0.20 lb/MMBtu for liquid or gaseous fuels. Compliance with the BACT standard ensures compliance with these standards. *{Permitting Note: Potential emissions of sulfuric acid mist are minimized by the effective control of SO_2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6 percent of the total measured SO_2 emissions.}*

d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations. Each cogeneration boiler is also subject to Rule 62-296.405(2)(a), F.A.C. and 40 CFR 60.42a, which limits visible emissions to no more than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Compliance with the BACT standard ensures compliance with these standards.

e. Compliance with the particulate matter standards shall be determined by the average of three test runs conducted in accordance with EPA Method 5. For purposes of reporting PM_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}. Each cogeneration boiler is also subject to Rule 62-296.405(2)(b), F.A.C. and 40 CFR 60.42a, which limits particulate matter emissions to 0.03 lb/MMBtu. Compliance with the BACT standard ensures compliance with these standards.

f. Compliance with the VOC standards shall be determined by the average of three test runs conducted in accordance with EPA Method 25A based on propane. In addition, the permittee may choose to conduct EPA Method 18 concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".

g. Compliance with the mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall install and operate a carbon injection system (or equivalent) for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

h. The particulate matter standard is also a surrogate standard for lead emissions. *{Permitting Note: For reporting purposes, average lead emissions are expected to be 2.6 x 10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9 x 10^{-04} lb/MMBtu when firing bagasse/wood.}*

i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19 and Appendix CT.

[Permit Nos. PSD-FL-196P and PSD-FL-196Q; Rules 62-4.070(3), Rule 62-210.200 (PTE), and 62-212.400 (BACT), F.A.C.]

14. <u>Rule 62-296.405(2), F.A.C.</u>: The cogeneration boilers are considered "Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input" and are subject to the following requirements for new units.

(a) Visible Emissions – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.42 and 60.42a).

(b) Particulate Matter – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.42 and 60.42a).

(c) Sulfur Dioxide – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.43 and 60.43a).

(d) Nitrogen Oxides – (See subsection 62-204.800(7), F.A.C., and 40 C.F.R. 60.44 and 60.44a).

The units were constructed in accordance with NSPS Subpart Da for Electric Utility Steam Generating Units. These provisions are included in Appendix 60Da of Section 4 of this permit.

15. <u>Rule 62-296.410, F.A.C.</u>: The cogeneration boilers are considered "Carbonaceous Fuel Burning Equipment" and are subject to the following requirements for new units with a maximum heat input rate equal to or greater than 30 MMBtu per hour.

a. Visible Emissions – 30 percent opacity except that a density of 40 percent opacity is permissible for not more than two minutes in any one hour.
b. Particulate Matter – 0.2 lb/MMBtu of heat input of carbonaceous fuel plus 0.1 lb/MMBtu of heat input of fossil fuel.

16. <u>Rule 62-296.570, F.A.C.</u>: The cogeneration boilers operate in Palm Beach County and are subject to the Reasonably Available Control Technology (RACT) Requirements for Major VOC- and NO_X-Emitting Facilities. Emissions of VOC and NO_X from carbonaceous fuel burning facilities, other than waste-to-energy facilities, shall not exceed 5.0 lb/MMBtu and 0.9 lb/MMBtu, respectively.

STARTUP, SHUTDOWN, AND MALFUNCTION

17. Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

a. *Definitions*

1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction.

2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). The ESP shall be placed on line at the earliest possible time during the startup period, consistent with the manufacturer's recommendations, operating experience and safety practices. Once the ESP is placed on line, the boiler shall comply with the specified opacity standard. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NO_X emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NO_X) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NO_X) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NO_X) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NO_X) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_2 emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]

4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NO_X monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups, shutdowns and documented malfunctions).

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

[Permit No. PSD-FL-196P; Rules 62-4.070(3), 62-210.200, and 62-210.700, F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

18. Startup/Shutdown Plan: The following procedures will be used to minimize the magnitude and duration of emissions during startup and shutdown.

a. *Startup Procedures*.

1) The ESP air flushing system and heater are placed in service at least eight hours prior to boiler light off.

2) The boiler is started up on natural gas or distillate oil prior to energizing the ESP.

3) The ESP shall be placed on line at the earliest possible time during the startup period, consistent with the manufacturer's recommendations, operating experience and safety practices. Once the ESP is placed on line, the boiler shall comply with the specified opacity standard. The ESP shall be on line and functioning properly before firing any biomass.

4) Manual controls are used to ensure optimum air-to-fuel ratios during the startup period.

5) The startup fuel is reduced gradually while the biomass firing rate is increased.

b. *Shutdown Procedures*.

1) Manual controls are employed to ensure optimum air-to-fuel ratios during the shutdown period.

2) For shutdown, the ESP is not deactivated until the fuel feed to the furnace is stopped.

[Application No. 0990005-017-AV]

TESTING

19. Stack Testing Requirements

a. *Initial Tests*: Initial tests were initially required for emissions of mercury, particulate matter, and volatile organic compounds. The Department may require these initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or pollution control equipment.

b. *Annual Tests*: At *least* once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

c. *Renewal Tests*: Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

d. *Test Procedures*: The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix CT of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45 percent wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100 percent biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. 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. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: As necessary, compliance with the emission limits specified in this permit shall be demonstrated using the following EPA Methods (or most recent versions), as contained in 40 CFR Parts 60 and 61.

EPA Method	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percent O_2
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits
5	Particulate matter emissions
6 or 6C	Sulfur dioxide emissions
7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity *{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}*
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions *{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".*
29	Multiple metals emissions
30B	Determination of Total Vapor Phase Mercury
101A	Particulate and gaseous mercury emissions

No other methods may be used to demonstrate compliance unless prior written approval is received from the Department. Other applicable testing requirements are included in Appendix CT of this permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NO_X, SO_2 and opacity. [Permit No. PSD-FL-196P; Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

MONITORING

20. CEMS and COMS: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate a COMS to continuously measure and record opacity and CEMS to continuously measure and record emissions of CO, NO_X, CO_2 (for O_2), and SO_2 in a manner sufficient to demonstrate compliance with the standards of this permit.

    a. *Performance Specifications.* Each monitor shall be located in the ductwork between the electrostatic precipitator and the stack (or in the stack) to obtain emissions measurements representative of actual stack emissions. Each CEMS and COMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements.

        1) Opacity shall comply with Performance Specification 1 in Appendix B of 40 CFR 60.

        2) The NO_X and SO_2 CEMS shall comply with Performance Specification 2 in Appendix B of 40 CFR 60. The SO_2 reference method for the annual RATA shall be EPA Method 6 (or 6C) in Appendix A of 40 CFR 60. The NO_X reference method for the annual RATA shall be EPA Method 7 (or 7E) in Appendix A of 40 CFR 60.

        3) The CO_2 CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The CO_2 reference method for the annual RATA shall be EPA Method 3A Appendix A of 40 CFR 60.

        4) The CO CEMS shall meet Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The CO reference method for the annual RATA shall be EPA Method 10 in Appendix A of 40 CFR 60.

    b. *Data Collection.* Each CEMS and COMS shall record emissions data at all times including episodes of startup, shutdown, and malfunction. Emissions data recorded during periods of startup, shutdown, or malfunction may only be excluded from the compliance averages in accordance with the requirements specified in Condition 17 of this subsection. To the extent practicable, the permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions.

        Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period. Each 1-hour average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. CO, NOx, and SO_2 CEMS shall express the 1-hour emission averages in terms of "lb/MMBtu of heat input". The CO_2 CEMS shall express the 1-hour emission average (CO_2 and O_2) in terms of "percent by volume". A 30-day rolling emission average shall be the average of all valid 1-hour emission averages collected during the 30-day period. A 12-month rolling emission average shall be the average of all valid 1-hour emission averages collected during the 12-month period. NO_X and SO_2 CEMS shall comply with NSPS Subpart Da in 40 CFR 60.

        Each COMS shall be designed and operated to 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. Opacity shall be recorded in 6-minute block averages.

    c. *Quality Assurance Procedures*. Each CEMS shall comply with the applicable quality assurance procedures specified in Appendix F of 40 CFR 60. These procedures include methods such as calibration, calibration drift, data recording, accuracy assessment, calculations, audit procedures, preventive maintenance, corrective actions, and reporting.

d. *Monitor Availability*. Monitor availability shall not be less than 95 percent in any calendar quarter. In the event 95 percent availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95 percent availability and a plan of corrective actions that will be taken to achieve 95 percent availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

e. *Other Applicable Requirements*: Each CEMS shall comply with the following applicable requirements Rules 62-204.800 (Federal Rule Adopted by Reference) and 62-297.520, F.A.C. (Continuous Monitor Performance Specifications); 40 CFR 60.13 (Subpart A - Monitoring Requirements); 40 CFR 60.47a (Subpart Da - Emissions Monitoring); 40 CFR 60.48a (Subpart Da - Compliance Determination Procedures and Methods); 60.49a (Subpart Da - Reporting Requirements).

[Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

21. Process and Control Parameters: The permittee shall install, calibrate, maintain, and operate continuous monitoring systems to measure and record the following process and control equipment parameters:

a. *Power Output.* The net power generation (MW) delivered for sale to the electrical power grid shall be continuously monitored and recorded in 1-hour block averages.

b. *Fuel Feed Rate.* Fuel flow meters equipped with totalizers are required to monitor and record the fuel feed rates for distillate oil (gallons) and natural gas (million cubic feet). Biomass feed rates (tons of bagasse and tons of wood) shall be calculated and recorded based on actual fuel flows. The permittee shall continuously monitor the fuel throughput rates based on the fuel flow monitors and calculate the actual heat input rates (24 hour average) for each fuel during each day of operation.

c. *Steam Parameters.* Each cogeneration boiler shall be equipped with monitors to measure and record the steam temperature (° F), steam pressure (psig), and steam production (pounds).

d. *Urea Injection Rate (SNCR System).* The urea injection rate shall be continuously monitored and recorded for each cogeneration boiler. The urea injection rate shall be compared to actual NO_X emissions data recorded by the CEMS. The permittee shall identify minimum urea injection rates for various load conditions that ensure compliance with the NO_X standards. Should the NO_X CEMS be unavailable, the urea injection rate shall be maintained at an appropriate minimum level.

~~e.~~ *Activated Carbon Injection Rate (Mercury Control System).* If the mercury injection system is installed, the carbon injection rate shall be continuously monitored and recorded. Based on the testing required in this permit, the permittee shall identify and maintain minimum carbon injection rates to ensure effective control of mercury emissions.

The permittee shall maintain written procedures for inspecting, calibrating, and maintaining the process and control monitoring equipment. [Permit No. PSD-FL-196P and PSD-FL-196Q; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

22. Power Generation: In conjunction with the Annual Operating Report, the permittee shall report the annual power generation (MWe-hours per year) for the previous calendar year and the 3-year average for the previous three calendar years. The report shall identify whether the cogeneration plant remains a “Qualifying Cogeneration Facility” as specified in 40 CFR Part 72 and is exempt from Acid Rain permitting. [40 CFR 72; Rule 62-4.070(3), F.A.C.]

RECORD KEEPING AND REPORTING

23. Fuel Records: The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log. In addition, the permittee shall abide by the Ash and Fuel Management Plans specified in Appendices AM and FM. [Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

24. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in the "Quarterly Report" included in Appendix QR of this permit. In addition to the information identified in this report, the permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The authorized representative shall certify that the information provided in each quarterly report is true, accurate, and complete to the best of his/her knowledge. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter. [Permit No. PSD-FL-196P; Rules 62-4.070 and 62-212.400 (BACT), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

25. NSPS Provisions: In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicable requirements of 40 CFR 60, including: Subpart A (General Provisions), Subpart Da (Standards of Performance for Electric Utility Steam Generating Units), Subpart DDDD, Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units, and NSPS Subpart Ea (Applicability for Standards of Performance for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994), and Subpart Ea (Applicability for Municipal Waste Combustors). The applicable provisions are specified in Appendices 60A, 60Da, 60DDDD, and 60Ea in Section 4 of this permit.

26. CAM Plan: Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C. and 40 CFR 64, the cogeneration boilers shall comply with the CAM plan specified in Appendix CM in Section 4 of this permit.

27. Subpart DDDDD Applicability: The cogeneration boilers are subject to the applicable provisions for existing units of NESHAP Subpart DDDDD in 40 CFR 63 for Industrial, Commercial, and Institutional Boilers and Process Heaters for major sources of HAP. The applicable requirements are contained in Appendix 63DDDDD in Section 4 of this permit. [NESHAP 40 CFR 63, Subpart DDDDD (dated January 31, 2013) and permit No. PSD-FL-196Q]

B. Material Handling and Storage Operations - Cogeneration Plant

This subsection addresses the following emissions units.

EU No.	Emissions Unit Description
004	**Cogeneration Plant - Material Handling and Storage** includes unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers and silos.

The materials handling and storage operations include authorization for truck and railcar unloading operations, storage piles, transfer operations, conveyors, screens, crushers, hoppers and silos. The materials authorized to be handled and stored include bagasse, authorized wood, fly ash, bottom ash, and a mercury removal agent (e.g., activated carbon). Unconfined particulate matter emissions from the operations shall be controlled by the use of the BACT controls and reasonable precautions specified in the following conditions.

EQUIPMENT SPECIFICATIONS

1. Equipment: The authorized methods of operation include the following:

   a. *Biomass Handling and Storage Operations*: The permittee is authorized to handle and store biomass fuels. The following activities are associated with these operations: truck unloading (dumps #1 and #2, unloading bay); chain conveyors (#1 and #2); unloading conveyor; disk screen; hogger; storage conveyor; radial stacker; biomass storage pile (active and inactive); underpile chain reclaimers (#1 and #2); boiler feed conveyor; boiler feed conveyor hopper; sugar mill bagasse feed conveyor; sugar mill bagasse conveyor hopper; chain distribution conveyors (#1 and #2); boiler meter bins; recycle conveyor; and the fixed recycle stacker.

   b. *Fly Ash Handling and Storage Operations*: The permittee is authorized to handle and store fly ash. The following activities are associated with these operations: boiler bank hoppers; air preheater hoppers; electrostatic precipitator hoppers; enclosed drag chain conveyors; fly ash storage silo (1,500 tons); fly ash pug-mill conditioners; fly ash truck load-out; mechanical dust collector hoppers; mixed (bottom and fly) ash conveyor belt; and mixed ash bunker. *{Permitting Note: The fly ash silo, fly ash pug mill conditioners and fly ash truck load-out have not operated for several years and the plant currently sends fly ash to the mixed ash conveyor belt and then to the mixed ash bunker.}*

   c. *Activated Carbon Handling and Storage Operations*: In the event that an Activated Carbon Injection system (ACI) is required to meet the permitted mercury emission limit, the mercury control system reactant storage silo(s) shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

      {Permitting Notes: If two or more cogeneration boilers exceed the annual mercury emission limit, the carbon injection system will be installed for all three boilers within 30 days of the stack test report due date.}

   d. *Bottom Ash Handling and Storage Operations*: The permittee is authorized to handle and store bottom ash. The following activities are associated with these operations: submerged and enclosed drag chain conveyors; transfer conveyor; collection conveyor; three-walled storage bunker; and bottom ash truck load-out.

   [Permit No. 0990332-020-AC (PSD-FL-196Q) Condition 17.(c.); Rules 62-4.160(2), 62-210.200 (Definitions), and 62-210.300, F.A.C.]

2. Baghouses: The fly ash storage silo shall be controlled by a baghouse and the three activated carbon silos shall be controlled by a single, common baghouse. Each baghouse shall be designed, operated and maintained to achieve an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust. New and

replacement bags shall meet this equipment specification based on vendor design information. No particulate matter emissions tests are required. When the mercury control system is operating, the activated carbon storage silos shall be maintained at a negative pressure with the exhaust vented through the baghouse. *{Permitting Note: The fly ash silo and fly ash silo baghouse have not been operated for several years and the plant currently sends fly ash to the mixed ash conveyor belt and then to the mixed ash bunker. In addition, the activate carbon silos have not been used for several years since the mercury limit can be met without the injection of activated carbon.}* [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

3. Ash and Fuel Management Plans: The permittee shall abide by the Ash and Fuel Management Plans specified in Appendix AM and FM, respectively. [Permit No. PSD-FL-196P]

4. Control Equipment O&M Plan: The permittee shall abide by the operation and maintenance (O&M) plans for the cogeneration plant control equipment specified in Appendix OM of this permit. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

5. Hours of Operation: The permittee is authorized to operate the materials handling and storage operations continuously (8760 hours per year). [Rule 62-210.200 (PTE), F.A.C.]

EMISSION LIMITING STANDARDS

6. Baghouse Vents: As determined by EPA Method 9, visible emissions from each baghouse vent shall not exceed 5 percent opacity. [Permit No. PSD-FL-196P; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

7. Fugitive Dust from Material Handling: The following conditions apply to the biomass and ash handling facilities.

   a. Except for those associated with the stacker/reclaimer, all conveyors and conveyor transfer points shall be enclosed to prevent fugitive particulate matter emissions.

   b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions shall not exceed 20 percent opacity.

   c. The fly ash handling system including all transfer points and the storage bin shall be enclosed. Bottom ash and fly ash shall be wetted and transferred in enclosed conveyors to the enclosed ash storage building. Alternatively, the ash shall be wetted and discharged to the ash storage silo.

   d. The distance that biomass fuel is dropped during handling shall be minimized.

   e. Windbreaks around the material handling equipment shall be used as necessary.

   f. Maintenance of paved areas as needed.

   [Permit No. PSD-FL-196P; Rules 62-4.070(3), 62-296.320(4)(c), and 62-212.400 (BACT), F.A.C.]

TEST REQUIREMENTS

8. Baghouse Vents: At least once during each federal fiscal year (October 1st through September 30th), the permittee shall test each silo baghouse vent in accordance with EPA Method 9. Due to infrequent use, the baghouse vent for the fly ash storage silo shall be tested during any federal fiscal year in which the fly ash storage silo operates more than 400 hours, and if the activated carbon injection system are installed and operate, the baghouse vent for the activated carbon silos shall be tested during any federal fiscal year in which the activated carbon injection system operates more than 400 hours. The baghouse vent for the activated

carbon silos shall be tested during a delivery of activated carbon. Tests shall be conducted in accordance with the applicable requirements in Appendix CT of this permit. The minimum observation period for an opacity test shall be 30 minutes. [Permit Nos. PSD-FL-196P and PSD-FL-196Q; Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

9. Test Reports: For each visible emissions test conducted, the permittee shall file a test report with the Department as soon as practical, but no later than 45 days after the last sampling run of each test is completed. Each test report shall include the information specified in Rule 62-297.310(8), F.A.C. as summarized in Appendix CT of this permit. [Rules 62-297.310(8), F.A.C.]

This subsection addresses the following emissions units.

EU No.	Emissions Unit Description
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1
022	Central Dust Collection System No. 2 with Rotoclone No. 2 – "B" System
023	Cooler No. 1 with Rotoclone No. 3
024	Cooler No. 2 with Rotoclone No. 4
025	Fluidized Bed Dryer/Cooler with Baghouse
034	Bulk Load-Out Operation w/ Baghouse
035	Transfer Bulk Load-out Station
043	Sugar Refinery Alcohol Usage
054	Wet Roto-clone No. 6 – "A" System (Permit No.0990005-027-AC)
055	Wet Roto-clone No. 7 - "C" System (Permit No. 0990005-027-AC)
059	Dust Collection System (Baghouse) – (Emissions control for Pkg. Lines 16, 17, 18 and 19)

{Permitting Note: The sugar refinery was last modified by Permit No. 0990005-030-AC.} (0990005-031-AC was a short term exemption for a temporary jaw crusher used in demolition of the carpenter shop and three adjacent concrete slabs). Permit No. 0990005-035-AC added a baghouse (EU-034) to the Bulk Load-Out, and Permit No. 09900050-037-AC added a baghouse and Packaging Lines No. 16, 17, 18 and 19 to Warehouse No.3. One of these was the original Packaging Line No. 5 in the Transhipment Facility (which is replaced by a brown Sugar packaging line of same capacity and re-designated as Packaging Line No. 5).

Miscellaneous Process Descriptions

The sugar refinery consists of several miscellaneous emissions units that handle, process, store, and transfer a variety of sugar products. These units and activities can generate emissions of particulate matter, mostly sugar. In 2008, Permit No. 0990005-021-AC authorized the expansion of the mill boiling house by installing new process equipment to produce specialty sugars products. The permit authorized: 1) an increase in the capacity of total refined sugar production; 2) an increase in the capacity of refined sugar production from the Fluidized Bed Dryer/Cooler baghouse system, the Bulk Load-out Station, and the Transfer Bulk Load-out Station; 3) a modification of Central Dust Collection System Nos. 1 and 2; an overall reduction in particulate matter emissions; and 5) alternative methods of operation for the Fluidized Bed Dryer/Cooler and the Rotary Dryer/Cooler systems.

The primary sugar drying system is a Fluidized Bed Dryer/Cooler (EU-025) with a design equipment capacity of approximately 1350 tons per day. Steam is used for the necessary heat and no fuels are fired in the dryer. The exhaust is controlled by a high efficiency baghouse manufactured by BETH GmbH, 23556 LÜB-beck (Type BETHPULS 6.60 x 7.5.10). The baghouse exhausts through a stack 93 feet above grade.

A Rotary Dryer (EU-021) is used for specialty sugars and when the fluidized bed dryer is off line for repairs. Steam is used for the necessary heat and no fuels are fired in the dryer. Dust emissions from the rotary dryer are controlled with the use of a skimmer followed by wet Rotoclone No. 1, (uses 2 gpm water injection), which exhausts 89 feet above grade. Sugar from the rotary dryer is directed to two coolers (EU-023 and EU-024), each with a design capacity of 1350 tons per day. The exhaust from Cooler No. 1 is controlled by Rotoclone No. 3 vented 80 feet above grade. The exhaust from Cooler No. 2 is controlled by Rotoclone No. 4 vented 80 feet above grade. The 3-stage high-production mode (rotary dryer followed by two coolers operating in series) is needed when producing approximately 1000 tons per day of refined white sugar and 600 tons per day of specialty sugars. When operating the rotary system in the low-production mode (< 1000 tons white sugar per day or < 600 tons specialty sugar per day), Cooler No. 1 (EU-023) functions as the dryer followed in series by Cooler No. 2 (EU-

024) and the rotary dryer remains shutdown. The Rotary System may operate simultaneously with the Fluidized Bed Dryer/Cooler.

Dust collection System "A", *Roto-clone No. 6* (EU-054) controls fourteen (14) drop points at the fluidized Bed System and fourteen (14) drop points at the Rotary Dryer System. The drop points include the following:

- Belt Conveyors 11(B) and GG(x2)
- Screw Conveyors Q1, 25, 25A, 28, 19, 46, Q2 and S1
- Bulk Curing Bins 1, 2, 3, or 7
- Bucket Elevators 10, 16, B, GG#5
- Sweco Shaker Screen
- Rotex Screen 9346 (to GG#8)

Dust Collection, System "B", Roto-clone No. 2 (EU-022) which exhausts 86 feet above grade, is used to control dust emissions from several miscellaneous sources. Total drop points controlled are twenty (20) at the Fluidized Bed System, and four (4) at the Rotary Dryer System. The drop points include the following:

- Belt Conveyor 19, 11(T), GG8(x2)
- Screw Conveyors 12(x3), 14, 20, 40, 45 and S2
- Packing Room Bins (5 pound and 100 pound)
- Bulk Curing Bins 4, 5, or 6
- Bucket Elevators 43 and 15
- Production Scale, Silo Scale, HN-1, Rotex

Dust Collection, System "C", *Roto-clone No. 7* (EU-055), controls twelve (12) drop points in the Fluidized Bed System, and one (1) drop point in the Rotary Dryer System. The drop points include the following:

- Belt Conveyors A(x2) and B(x2)
- Screw conveyors 20A, 26, 27, 29, 30, 42, and N
- Reject Chute

The Bulk Load-Out Operation (EU-034) with a design equipment capacity of 600 tons per day is used to load sugar into either trucks or railcars. The operation includes a silo and a three-sided building. Emissions of fugitive particulate matter are controlled by a *baghouse that was authorized to be constructed by Air Construction permit No. 0990005-035-AC.*

The Transfer Bulk Load-Out Station (EU-035) with a design equipment capacity of 1200 tons per day is used to supply sugar to the Transshipment Facility. The operation includes four enclosed conveyors in series feeding refined sugar from the storage silo or bulk curing bins to an enclosed load-out building. Emissions of fugitive particulate matter are controlled by use of the enclosure and high-pressure air curtains.

The expansion project extended by 40 feet the south end of the sugar refinery building (now 40 feet by 120 feet), which houses the following associated process equipment: The following equipment will be housed in the expansion: two melters, two syrup tanks, two grain receiver tanks, two vacuum pans, two magma/cut tanks, two batch centrifuges, two molasses tanks, two screw conveyors, one magma mingler, one run-off tank, a motor control center room, and various pumps and piping systems. The other portion of the existing sugar refinery building houses the following associated process equipment: a 1700-cubic feet vacuum pan, a vacuum pan condenser, two centrifugals, syrup and molasses feed tanks, final liquor syrup storage tanks, one 5000 gallon condensate collection tank, one 1000 gallon centrifugal wash water tank, two 1200 cubic feet seeder cutover tanks, a motor control center room, the motor control center and centrifugal controller room, a refined sugar conveying system, one 2000 cubic feet receiver and various pumps.

Two types of alcohol, isopropyl alcohol and organic ethanol, are used in the sugar refinery to aid in the crystallization process in the vacuum pans (EU-043). Isopropyl alcohol is used in the production of standard refined sugar and is the primary source of VOC emissions. Organic ethanol is used in the production of organic sugar.

D. Sugar Refinery

A Baghouse (Dust Collection System (EU-059) and four (4) sugar packaging lines (Packaging Lines No. 16, 17, 18 and 19), are located in Warehouse No. 3. The additional packaging lines are a separate operation from the existing speciality Sugar production in Warehouse No. 3. Two (2) rooms are built into the interior of the warehouse. Two (2) packaging lines to package artificial sweeteners are installed in one (1) room (Packaging Lines No. 16 and 17) and two (2) packaging lines for speciality sugars are housed in the second room (Packaging Lines No. 18 and 19). (One (1) of these packaging lines is actually the existing packaging line No. 5 located in the Transshipment Facility which is relocated to Warehouse No.3. It is replaced in the Transshipment Facility by a brown sugar packaging line of the same capacity and it is re-named as Packaging Line No. 5).
(Permit No. 0990009-037-AC).

The potential emissions from the packaging lines consists of particulate matter (PM) in the form of sugar dust, and all four (4) packaging lines are controlled by one (1) dust collector (baghouse) (EU-059).

For the sugar refinery, dust-generating activities that are completely enclosed and vented within the building are not classified as air pollution sources.

EQUIPMENT SPECIFICATIONS

1. Baghouse Specifications:

FLUIDIZED BED DRYER (EU-025)

To control emissions from the fluidized bed dryer (EU-025), the permittee shall operate and maintain a baghouse control system with the following specifications:

Parameter	Specification
Design exhaust flow rate	70,620 acfm
Filtering area	9041 ft^2
Air-to-cloth ratio	7.81 cfm/ft^2
Control efficiency	99.8% (PM and PM_{10})

[Rule 62-4.070(3), F.A.C. and Permit No. 0990005-021-AC]

BULK LOAD-OUT OPERATION (EU-034)

The 3,400 acfm Baghouse (Dust Collection System) controls particulate emissions (PM)

To control particulate emissions from the Bulk Load-Out Operation (EU-034), the permittee shall operate and maintain a baghouse control system with the following specifications:

Parameter	Specification
Design exhaust flow rate	3,400 acfm
Filtering area	1436 ft^2
Air-to-cloth ratio	2.2:1 cfm/ft^2
Control efficiency	99.8% (PM and PM_{10})

[Rule 62-4.070(3), F.A.C. and Permit No. 0990005-035-AC]

PACKAGING LINES No. 16, 17, 18 & 19 (EU-059)

The 3,400 acfm Baghouse (Dust Collection System) controls particulate emissions (PM)

To control particulate emissions from Packaging Lines No. 16, 17, 18 and 19 in Warehouse No. 3, the permittee shall operate and maintain a baghouse control system with the following specifications:

Parameter	**Specification**
Design exhaust flow rate	3,400 acfm
Filtering area	1436 ft^2
Air-to-cloth ratio	2.2:1 cfm/ft^2
Control efficiency	99.8% (PM and PM_{10})

2. Cyclonic Control Devices: The permittee shall operate and maintain the following emission units and corresponding control equipment in accordance with the specifications identified in the table below:

EU No.	**Description**	**Control Type**	**Design Flow Rates acfm**	**Water Injection Rate (gpm, min.)**	**Control Efficiency**	
					PM	**PM_{10}**
021	Rotary Dryer, Central Dust Collection System No. 1	Roto-clone No. 1	15,000	2	99.9%	99%
022	"B" System	Roto-clone No. 2	14,770	2	99.9%	99%
023	Cooler No. 1	Roto-clone No. 3	15,000	2	99.9%	99%
024	Cooler No. 2	Roto-clone No. 4	15,000	2	99.9%	99%
054	"A" System	Roto-clone No. 6	15,078	2	99.9%	99%
055	"C" System	Roto-Clone No. 7	12,895	2	99.9%	99%

[Rule 62-4.070(3), F.A.C. and Permit No. 0990005-021-AC and 0990005-027-AC]

CAPACITY AND PERFORMANCE RESTRICTIONS

3. Permitted Capacities: Total refined sugar production (Fluidized Bed Dryer (EU-025), Rotary Dryer (EU-021), Cooler No. 1 (EU-023) and Cooler No. 2 (EU-024) shall not exceed 490,000 tons during any consecutive 52-week period, and:
    a. The Rotary System (EU-021, EU-023 and EU-024) shall not process more than 130,000 tons during any consecutive 52-week period.
    b. The Bulk Load-Out Operation (EU-034) shall not process more than 139,000 tons of refined sugar during any consecutive 52-week period. [Rules 62-4.210, 62-4.070(3) and 62-210.200(PTE), F.A.C and Permit No. 0990005-035-AC]
    c. The Transfer Bulk Load-Out Station (EU-035) shall not process more than 351,000 tons of refined sugar during any consecutive 52-week period.
    d. Isopropyl alcohol usage (EU-043) from the sugar refinery shall not exceed 78,040 pounds during any consecutive 52-week period.
    e. Production rate for the four (4) combined packaged Sugar/Sweeteners (Packaging Lines No. 16, 17, 18 and 19) is 181.2 Tons Per Day (TPD). [Permit No. 0990005-037-AC].

    [Rules 62-4.210 and 62-4.070(3), F.A.C.; and Permit No. 0990005-021-AC, 0990005-027-AC, 0990005-035-AC and 0990005-037-AC]

4. Hours of Operation: Operation of the sugar refinery is limited by the limitations on processing capacities. The hours of operation are not limited (8,760 hours per year). [Permit No. 0990005-021-AC, 0990005- 027-AC And 0990005-035-AC]

METHODS OF OPERATION

5. Method of Operation: The owner or operator is authorized to operate the dryers in any of the following methods.
    a. The Fluidized Bed Dryer (EU-025) only;
    b. Rotary System only:
        1) 3-Stage High-Production Mode: The Rotary Dryer (EU-021) is operated with Cooler No. 1 (EU-023) and Cooler No. 2 (EU-024) in series. In this mode, high production rates are approximately 1000 tons per day for white refined sugar and above 600 tons per day for specialty sugars.
        2) 2-Stage Low-Production Mode: The Rotary Dryer (with Rotoclone No. 1, EU-021) is off and Cooler No. 1 (with Rotoclone No. 3, EU-023) is operated as a dryer followed by Cooler No. 2 (with Rotoclone No. 4, EU-024) in series. In this mode, low production rates are below 500 tons per day for specialty sugars.
    c. The Fluidized Bed Dryer (EU-025) and Rotary System (EU-021, EU-023 and EU-024) may be operated simultaneously. The dryers and sugar refinery are subject to the production and processing limitations specified in Specific Condition No. 3 of this subsection. [Permit No. 0990005-021-AC and -027-AC.

EMISSION LIMITING STANDARDS

6. Visible Emissions:

   a. Visible emissions shall not exceed 5 percent opacity from the following exhaust points: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 with "B" System Roto-clone No. 2 (EU-022); Cooler No. 1 with Roto-clone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); Also "A" System "Roto-clone No. 6 (EU-054), "C" System Roto-clone No. 7, (EU-055), Fluidized Bed, Dryer/Cooler Baghouse (EU-025) and Baghouse for Packaging Lines No. 16, 17, 18 and 19. (EU-059).

   b. Visible emissions shall not exceed 5 percent opacity from the following areas: the Bulk Load-Out Operation (EU-034), the Transfer Bulk Load-out Station (EU-035) and fugitive emissions at the sugar refinery.

   [Rules 62-296.320(4) and 62-297.620(4), F.A.C.; and Permit No. 0990005-035-AC]

7. PM/PM10 Emissions): The sum of emissions shall not exceed 19.77 tons of PM per year and 2.9 tons of PM_{10} per year from the following emission units: the Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1 (EU-021); the Central Dust Collection System No. 2 ("B" System) with Rotoclone No. 2 (EU-022); the Cooler No. 1 with Rotoclone No. 3 (EU-023); the Cooler No. 2 with Rotoclone No.4 (EU-024); the Fluidized Bed Dryer/Cooler with Baghouse (EU-025); "A" System Roto-clone No. 6 (EU-054); "C" System Roto-clone No. 7 (EU-055); the Bulk Load-Out Operation (EU-034); and the Transfer Bulk Load-out Station (EU-035). [Rule 62-210.200(PTE), F.A.C. and Permit No. 0990005-035-AC]

8. Potential PM/PM10 Emissions: For informational purposes only, the following table summarizes the potential emissions from the sugar refinery emissions units:

EU No.	Description	Tons/Year	
		PM	PM_{10}
021	Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1	4.09	1.645
022	Central Dust Collection System No. 2 with Roto-clone No. 2 ("B" System)	0.44	0.174
023	Cooler No. 1 with Roto-clone No. 3	4.09	1.64
024	Cooler No. 2 with Roto-clone No.4	0.45	0.18
025	Fluidized Bed Dryer/Cooler with Baghouse	14.70	0.588
034	Bulk Load-Out Operation	3.63	0.15
035	Transfer Bulk Load-out Station	1.83	0.07
054	Roto-clone No. 6 ("A"System)	0.51	0.205
055	Roto-clone No. 7 ("C" System)	0.38	0.154
059	*Baghouse, Pkg. Lines 16, 17, 18 & 19*	1.28	0.520

[Permit No. 0990005-021-AC, 0990005-035-AC and 0990005-037-AC]

9. PM/PM10 Emission Factors: The permittee shall use the following emission factors to calculate PM/PM_{10} emissions (including calculations for the Annual Operating Report).

EU No.	Description	PM		PM_{10}	
		Uncontrolled	**Control Efficiency**	**Uncontrolled**	**Control Efficiency**
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1	3.150% (from dryer)	99.9%	0.125% (from dryer)	99.0%
022	Central Dust Collection System No. 2 with Rotoclone No. 2 ("B" System)	1.777 lb/ton	99.9%	0.071 lb/ton	99.0%
023	Cooler No. 1 with Rotoclone No. 3	0.175%	99.9%	0.007%	99.0%
024	Cooler No. 2 with Rotoclone No.4	0.175%	99.9%	0.007%	99.0%
025	Fluidized Bed Dryer/Cooler with Baghouse	1.5%	99.8%	0.060%	99.8%
034	Bulk Load-Out Operation *with Baghouse*	0.105 lb/ton	50%	0.00418 lb/ton	50%
035	Transfer Bulk Load-out Station	0.105 lb/ton	90%	0.00418 lb/ton	90%
054	Roto-clone No. 6 ("A" System)	1.045 lb/ton	99.9%	0.042 lb/ton	99.0%
055	Roto-clone No. 7 ("C" System)	0.105 lb/ton (Rotary Dryer) 1.463 lb/ton (Fluidizer Drying)	99.9%	0.0042 lb/ton (Rotary Dryer) 0.059 lb/ton (Fluidizer Drying)	99.0 %
059	*Pkg. Lines 16, 17, 18 & 19 with Baghouse (Warehouse 3).*	0.105 lb/ton	99.9%	0.00418 lb/ton	99.9%

[Permit No. 0990005-021-AC, 0990005-027-AC, 0990005-035-AC and 0990005-037-AC]

10. Alcohol Usage: VOC emissions from alcohol usage shall not exceed 39.00 tons during any consecutive 52-week period. *(Permitting Note: VOC emissions are contributed mainly from isopropyl alcohol.)* [Permit No. 0990005-021-AC]

TESTING REQUIREMENTS

11. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the following baghouse and Roto-clone exhaust points shall be tested to demonstrate compliance with the (VE) opacity standard specified in this subsection: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 ("B" System) with Roto-clone No. 2 (EU-022); Cooler No. 1 with Roto-clone No. 3 (EU-023); Cooler No. 2 with Roto-clone No.4 (EU-024); Fluidized Bed Dryer/Cooler with Baghouse (EU-025); Bulk Load-Out Operation (EU-034),"A" System with Roto-clone No. 6 (EU-054); "C" System with Roto-clone No. 7 (EU-055) and Baghouse, Pkg. Lines 16, 17, 18 & 19 (EU-059).

[Rule 62-297.310(7)(a)4, F.A.C. and Permit No.0990005-021-AC, 0990005 -027-AC, 099005-035-AC and 0990005-037-AC].

12. Tests Prior to Renewal: Within the 12-month period prior to renewing the operation permit, the following baghouse and Rotoclone exhaust points shall be tested to demonstrate compliance with the (VE) opacity standard specified in this subsection: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 with "B" System Roto-clone No. 2 (EU-022); Cooler No. 1 with Rotoclone No. 3 (EU-023); Cooler No. 2 with Rotoclone No.4 (EU-024); and Fluidized Bed Dryer/Cooler with Baghouse (EU-025). Bulk Load-Out Operation (EU-034), "A" System Roto-clone No. 6 (EU-054)"C" System Roto-clone No. 7 (EU-055) and Baghouse, Pkg. Lines 16, 17, 18 & 19 (EU-059). [Rule 62-297.310(7) (a) 3, F.A.C.]

    Test Method: Tests to determine visible emissions shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.310(4), F.A.C.; 40 CFR 60, Appendix A; and Permit No. 0990005-021-AC, 0990005-027.

13. PM Testing: The PM compliance test requirements are waived in lieu of the alternative opacity standard of 5 percent for: Rotary Dryer, Central Dust Collection System No. 1 with Roto-clone No. 1 (EU-021); Central Dust Collection System No. 2 with Roto-clone No. 2 (EU-022) "B" System; Cooler No. 1 with Rotoclone No. 3 (EU-023); Cooler No. 2 ,with Roto-clone No.4 (EU-024); Fluidized Bed Dryer/Cooler with Baghouse (EU-025); Bulk Load-Out Operation (EU-034),"A" System with Roto-clone No. 6 (EU-054); "C" System with Roto-clone No. 7 (EU-055) and Baghouse, Pkg. Lines 16, 17, 18 & 19 (EU-059).

14. If the Department has reason to believe that the particulate weight emission standard applicable to the emission unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule. [Rule 62-297.620(4), F.A.C. and 62-4.070(3), F.A.C.]

15. Test Procedures:
    a. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CT (Compliance Testing Requirements).
    b. The minimum observation period for a visible emissions compliance test shall be 30 minutes.
    c. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
    d. The permittee shall record the actual sugar processing rate for the emissions units being controlled and tested. [Rule 62-297.310, F.A.C. and Permit No.: 0990005-021-AC]

16. Test Notification: At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the test to be conducted; the date, time and the place of the test; and the contact person who will be responsible for coordinating and having the test conducted. [Permit No. 0990005-021-AC; Rule 62-297.310(7), F.A.C.]

RECORDKEEPING AND REPORTING REQUIREMENTS

17. Test Reports: For each visible emissions test conducted, the permittee shall submit a test report to each Compliance Authority as soon as practical, but no later than 45 days after the last sampling run of each test is completed. Each test report shall include the information specified in Rule 62-297.310(8), F.A.C. [Rule 62-297.310(8), F.A.C. and Permit No. 0990005-021-AC, 0990005-035-AC and 0990005-037-AC].

18. Operational Data: The permittee shall maintain daily and weekly records to demonstrate compliance with the permit limitations specified in Specific Condition No. 3 of this permit. The daily and weekly records shall include, at a minimum, the following: the date; the hours of operation; the total refined sugar produced; the refined sugar produced from the fluidized bed sugar drying system; the refined sugar production from the rotary sugar dryer system (including coolers); quantity of refined sugar handled through the bulk load out area; quantity of refined sugar handle through the transshipment load out area; weekly use of isopropyl alcohol and

organic ethanol; and weekly rolling consecutive 52-week period total for all permitted refined sugar production limits. [Rule 62-4.070(3), F.A.C. and Permit No. 0990005-021-AC, 0990005-027-AC and 0990005-035-AC].

E. Transshipment Facility

This section of the permit addresses the following emissions units.

ID	Emission Unit Description	ID	Emission Unit Description
018	Central vacuum system No. 1	**045**	Powdered sugar dryer/cooler, packaging Line 8A and 8B
019	Sugar packaging Lines 0-9, including 8A and 8B	**046**	Powdered sugar hopper
020	Sugar grinder	**047**	Sugar packaging lines (12-14)
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)	**049**	Baghouse (Currently inactive).
031	Railcar sugar unloading receiver No. 1		
032	Railcar sugar unloading receiver No. 2		

{Permitting Note: Permit Nos. 0990005-019-AC and 0990005-023-AC re-defined the equipment and capacity of the transshipment facility.}

Process Description

Sugar received at the transshipment facility is either directly packaged or temporarily stored before packaging. Extra-fine granulated sugar from the refinery is delivered to the transshipment facility at one of three locations. At the east truck receiving dock, trucks are pneumatically unloaded into a main sugar receiver, which pneumatically transfers sugar into surge bins above the packaging lines. At the north side of the facility, trucks are unloaded at a bulk receiving station by locking a boot mechanism against the truck's hopper and sugar is transferred from trucks by screw conveyors to a bucket elevator feeding one of three storage silos (EU-030). At the north railcar receiving station just west of the sugar silos, railcars will be pneumatically unloaded into two sugar receivers (EU-031 and EU-032) for transfer by screw conveyor to a bucket elevator feeding one of three storage silos. Each sugar receiver is controlled by a baghouse. The west receiver will also transfer sugar directly to a surge bin for packaging line "0", which will be used to fill totes north of packaging line "1" in the existing packaging room.

Each of the three storage silos (EU-030) is 12 feet in diameter of 12 feet, 68 feet tall, and has a volume of approximately 4,600 cubic feet. Each silo is controlled by a baghouse. Sugar is transferred from each silo by screw conveyor into surge bins located above packaging lines.

Sugar is packaged in one of 14 packaging lines, which are controlled by baghouse systems (Lines 0-8A and 8B-9 (EU-019), Lines 12, 13 and 14 (EU-047). Packaging Lines 8A and 8B vent to the baghouses associated with EU-019 and EU-045. Packaging Line 11 vents to the main sugar receiver. Baghouse (EU-049) is currently inactive. Sugar is metered from surge bins above the packaging lines for processing into a variety of packages and containers for wholesale and retail distribution.

The Trans-Shipment Facility, Packaging line 10 Baghouse is <u>EXEMPT</u> (Permit No. 0990005-029-AC and -030-AC) as it is vented to outside of the refinery building with minimal emissions. (The total emissions from this baghouse are calculated at 0.15 pound/hr. and 0.64 tons/year).

A small portion of extra-fine granulated sugar is conveyed to the sugar grinder (EU-020) and mixed with starch to produce powdered sugar. The sugar grinder is used to reduce the sugar solids to a desired particle size. The grinder has a design capacity of approximately 4 tons per hour. The powdered sugar dryer/cooler (EU-045) and the powdered sugar hopper (EU-046) are also used in this process. In addition, brown sugar may be produced by mixing light or dark molasses with the extra fine granulated sugar. All units are controlled by baghouse systems.

A central vacuum system (EU-018) is used periodically for house keeping purposes. The system includes various pick-up points throughout the transshipment facility and is equipped with a cyclonic separator followed by a baghouse. The system has no restrictions on the number or types of pick-up points.

EQUIPMENT SPECIFICATIONS

1. Baghouse Design Specifications: Each of the following emissions units shall be controlled by a baghouse that is designed, operated, and maintained to achieve the particulate matter baghouse design specification (grains/scf) identified in the following table.

ID	Emission Unit Description	Baghouse Specification [a] grains/scf	Exhaust Rate scfm	Stack/Vent Height Feet	Maximum Emissions [b]	
					lb/hour	tons/year
018	Central vacuum system No. 1	0.01	280	8	0.024	0.11
019	Sugar packaging Lines 0-9, including 8A and 8B	0.01	9869	27	0.85	3.71
020	Sugar grinder	0.0005	2961	39	0.013	0.06
030	Sugar silo No. 1 (Point #S1101)	0.02	500	65	0.086	0.38
	Sugar silo No. 2 (Point #S1102)	0.02	500	65	0.086	0.38
	Sugar silo No. 3 (Point #S1103)	0.02	500	65	0.086	0.38
031	Railcar unloading receiver No. 1	0.02	615	5	0.11	0.46
032	Railcar unloading receiver No. 2	0.02	615	5	0.11	0.46
045	Powdered sugar dryer/cooler, packaging Lines 8A and 8B	0.01	8640	48	0.74	3.24
046	Powdered sugar hopper	0.01	1728	42	0.15	0.68
047	Sugar packaging Lines 12, 13 and 14	0.01	3629	48	0.49	2.16
049	Baghouse (currently inactive)	0.02	2212	9	0.38	1.66
					Total	13.68

a. New and replacement bags shall meet these specifications based on vendor information. No particulate matter emissions tests are required.

b. These rates represent the maximum expected emissions based on the baghouse design specification, the maximum exhaust flow rates, and 8,760 hours of operation per year. These rates are not enforceable emissions standards.

[Permit Nos. 0990005-019-AC and 0990005-023-AC]

CAPACITY AND PERFORMANCE RESTRICTIONS

2. Permitted Capacity: The maximum sugar packaging rate is 1,300 tons per day. [Permit Nos. 0990005-019-AC and 0990005-023-AC and Title V application received May 15, 2012]; Rule 62-210.200 (PTE), F.A.C.]

3. Restricted Operation: The hours of operation of are not limited (8,760 hours per year). [Permit Nos. 0990005-019-AC and 0990005-023-AC; and Rule 62-210.200 (PTE), F.A.C.]

EMISSION LIMITING STANDARDS

4. Opacity Standard: As determined by EPA Method 9 observations, visible emissions from each baghouse exhaust point shall not exceed 5 percent opacity. [Permit Nos. 0990005-019-AC and 0990005-023-AC; and Rule 62-4.070(3), F.A.C.]

TESTING

5. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard. [Rule 62-297.310(7)(a)4, F.A.C.]
6. Tests Prior to Renewal: Within the 12-month period prior to renewing the operation permit, each baghouse exhaust point shall be tested to demonstrate compliance with the specified opacity standard. [Rule 62-297.310(7)(a)3, F.A.C.]
7. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required test. [Rule 62-297.310(7)(a)9, F.A.C.]
8. Test Method: All tests shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Tests shall also comply with the applicable requirements of Rule 62-297.310, F.A.C. See Appendix CT. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]
9. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C. as specified in Appendix CT. The minimum observation period for a visible emissions compliance test shall be 30 minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. The permittee shall record the actual sugar processing rate for the emissions unit being controlled and tested. [Rule 62-297.310(4) and (5), F.A.C.]
10. Test Notification: At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the date, time, and place of the test; and the contact person who will be responsible for coordinating and having the test conducted. [Rule 62-297.310(7)(a)9, F.A.C.]

RECORD KEEPING AND REPORTING

11. Test Reports: For each visible emissions test conducted, the permittee shall file a test report including the information specified in Rule 62-297.310(8), F.A.C. with the Compliance Authority as soon as practical, but no later than 45 days after the last sampling run of each test is completed. See Appendix CT in Section 4 of this permit. [Rules 62-297.310(8), F.A.C.]
12. Operational Data: The permittee shall maintain daily and monthly records to demonstrate compliance with the specified maximum sugar packaging rate. [Permit Nos. 0990005-019-AC and 0990005-023-AC; and Rule 62-4.070(3), F.A.C.]

OTHER APPLICABLE REQUIREMENTS

13. Compliance Plan: The permittee shall comply with the provisions of the Compliance Plan as specified in Appendix CP in Section 4 of this permit. [Rule 62-213.440(2), F.A.C.]

F. Distillate Oil Storage Tanks

This subsection addresses the following emissions units.

ARMS ID No. 0990332 - New Hope Power Company's Okeelanta Cogeneration Plant

EU No.	Emissions Unit Description	Process Area
005	Distillate Oil Storage Tank (50,000 gallons)	Cogeneration Plant

ARMS ID No. 0990005 – Okeelanta Corporation's Sugar Mill and Refinery

EU No.	Emissions Unit Description	Process Area
015	*Distillate Oil Storage Tank - (DELETED)*	*Sugar Mill and Refinery*
016	*Distillate Oil Storage Tank, - (DELETED)*	*Sugar Mill and Refinery*
017	*Distillate Oil Storage Tank - (DETETED)*	*Sugar Mill and Refinery*
040	Facility Fuel Tank Farm	Facility

EQUIPMENT CAPACITIES AND PERFORMANCE RESTRICTIONS

1. Oil Storage Tanks:
   a. *ARMS ID No. 0990332*: The distillate oil storage tank (EU-005) has a capacity of 50,000 gallons. [Permit No. 0990005-016-AC]
   b. Miscellaneous tanks installed on or before July 23, 1984 are not subject to the NSPS Subpart Kb provisions in 40 CFR 60. Fuel and oil tanks with a storage capacity of 19,813 gallons or less are not subject to NSPS Subpart Kb provisions. Fuel and oil tanks with a storage capacity between 19,813 gallons and 39,890 gallons shall store only volatile organic liquids with a maximum true vapor pressure of less than 15.0 kilopascals (kPa) or 2.17 pounds per square inch, absolute (psia). Fuel and oil tanks with a storage capacity of 39,890 gallons or more shall store only volatile organic liquids with a maximum true vapor pressure of less than 3.5 kPa (0.51 psia). This condition ensures that the storage tanks are not subject to the NSPS Subpart Kb provisions in 40 CFR 60. [NSPS Subpart Kb, §60.110b] [Rule 62-210.200 (PTE), F.A.C.]

RECORDS

2. Records: The permittee shall maintain records of the types and amounts of fuel stored in each tank. Distillate oil shall meet the requirements of the Ash and Fuel Management Plans in Appendix AM and FM of this permit. [Rule 62-4.070(3), F.A.C.]

G. Paint Spray Booth – Farm Operations

This permit addresses the following emissions unit:

EU No.	Emissions Unit Description	Process Area
048	Paint Booth	Okeelanta Shop

{Permitting Note: Permit No. 0990005-015-AC redefined this emissions unit. The paint spray booth is the drive-through model of the Crossflo truck spray booth manufactured by AFC, Inc. (Model Number TSD6036). The paint booth has the potential to emit 9.40 tons per year of volatile organic compound (VOC), 0.47 tons per year of hazardous air pollutants (HAPs), and 0.35 tons per year of particulate matter (PM/PM_{10}).}

EQUIPMENT SPECIFICATIONS

1. Method of Operation. Paint shall only be applied to agricultural equipment, trailers, and other vehicles or facility equipment. Paint shall be applied by compressed air spray gun, airless paint sprayer or other equipment with equivalent transfer efficiency. Compressed air systems typically use house air within a pressure range of approximately 60 to 80 pounds per square inch (psi). Airless systems typically operate at a pressure of approximately 3,200 psi. There are two exhaust stacks for the paint spray booth. Both are 25.7 feet tall with a 4-foot diameter and have a flow rate of 45,500 actual cubic feet per minute (acfm). [Permit Nos. 0990005-015-AC and 0990005-016-AC]

EMISSIONS LIMITING AND PERFORMANCE RESTRICTIONS

2. Hours of Operation: The hours of operation for this emissions unit are not restricted (8,760 hours per year). [Permit No. 0990005-015-AC; Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

3. Permitted Capacity: The maximum throughput rate of paint and thinner shall not exceed 4,950 gallons in any consecutive 12 months. [Permit No. 0990005-015-AC; Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

4. VOC Emissions: Emissions of volatile organic compounds (VOC) shall not exceed 9.40 tons in any consecutive 12 months. The permittee may adjust the amounts and types of coatings used as necessary to comply with this standard. Coatings and thinners used in the spray booth are not restricted to specific products or manufacturers. The permittee may substitute coatings and thinners and adjust the amounts of coatings and thinners used, as needed. [Specific Conditions 7 and 9 in Permit No. 0990005-015-AC; Rule62-210.200 (PTE), F.A.C.]

5. Visible Emissions: Visible emissions from the paint spray booth shall not exceed 20 percent opacity. [Specific Condition 12 in Permit No. 0990005-015-AC; Rule 62-296.320 (General VE), F.A.C.]

6. Fugitive VOC: All equipment, pipes, hoses, containers, lids, fittings, etc., shall be operated and maintained in such a manner as to minimize leaks, fugitive emissions, and spills of materials containing volatile organic compounds (VOC). [Permit No. 0990005-015-AC; Rule 62-210.200 (PTE), F.A.C.]

TESTING

7. Special Compliance Tests: In accordance with Rule 62-297.310(7)(b), F.A.C., the Compliance Authority may require a compliance test for visible emissions. [Permit No. 0990005-015-AC; Rule 62-297.310(7)(b), F.A.C.]

RECORD KEEPING AND REPORTING

8. Operational Records: For each month, the permittee shall record and maintain records of the following: the number of actual hours of operation for the paint booth; the dates of operation; the amounts and types of coatings, thinners and cleanup solvents used; and a monthly calculation of the volatile organic compounds and hazardous air pollutants emitted from the paint booth. VOC/HAP emissions shall be calculated by

assuming that all VOC/HAP in the coatings, thinners and cleanup solvents evaporate. The mass fraction of VOC/HAP from each solvent-containing material shall be determined from the Material Safety Data Sheets (MSDS) supplied by the vendors. The permittee shall maintain a file of MSDS for each solvent-containing material that indicates the composition of the VOC/HAP. Solvent-containing materials include, but are not limited to, powder coatings, solvent coatings, thinners, and cleanup solvents. The file must be maintained on site and made available for inspection upon request. The permittee shall have until the last day of the following month to complete these records. The amounts and types of coatings used and the calculated VOC and HAP emissions shall be included in the required Annual Operating Report. [Permit 0990005-015-AC; Rules 62-210.370 and 62-4.070(3), F.A.C.]

Contents

Title V Air Operation Permit Renewal
Permit No. 0990005-038-AV
(Revises Operating Permit No. 0990005-034-AV)

APPLICANT

The applicant for this project is Okeelanta Corporation. The applicant's responsible official and mailing address is: Jose Gonzalez, Vice President of Industrial Operations, Okeelanta Corporation, Okeelanta Sugar Mill, 21250 U.S. Highway 27 South, South Bay, Florida, 33493.

FACILITY DESCRIPTION

The applicant operates the existing Okeelanta Sugar Mill, which is located in Palm Beach County at 21250 U.S. Highway 27 South, South Bay, Florida. The facility consists of two adjacent plants. Okeelanta Corporation (ARMS ID No. 0990005) operates an existing sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) including sugar packaging and transshipment activities. New Hope Power Company (ARMS ID No. 0990332) operates an existing cogeneration plant that provides process steam for the sugar mill and refinery operations as well as generating electricity for sale to the power grid (SIC 4911). The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the PSD and Title V regulatory programs. The primary sources of air pollution include: Three (3) - 760 million British thermal units per hour (MMBtu/hr) per hour cogeneration boilers; transfer and storage of wood chip and bagasse fuels; distillate oil storage tanks; Sugar Refinery, Transshipment Facility, transfer and storage of sugar; and a paint spray booth. The facility includes other miscellaneous "unregulated" emissions units and activities.

This project pertains to the Sugar Refinery which consists of several miscellaneous emissions units that handle, process, store, and transfer a variety of sugar products. These units and activities can generate emissions of particulate matter, mostly sugar.

The Sugar Refinery consists of the following units:

EU No.	Emissions Unit Description
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1
022	Central Dust Collection System No. 2 with Rotoclone No. 2 – "B" System
023	Cooler No. 1 with Rotoclone No. 3
024	Cooler No. 2 with Rotoclone No. 4
025	Fluidized Bed Dryer/Cooler with Baghouse
034	Bulk Load-Out Operation w/ Baghouse
035	Transfer Bulk Load-out Station
043	Sugar Refinery Alcohol Usage
054	Wet Roto-clone No. 6 – "A" System (Permit No.0990005-027-AC)
055	Wet Roto-clone No. 7 - "C" System (Permit No. 0990005-027-AC)
059	Dust Collection System (Baghouse) – (Emissions control for Pkg. Lines 16, 17, 18 and 19)

This facility also includes miscellaneous unregulated/insignificant emissions units and/or activities.

The Transshipment Facility consists of the following Units:

ID	Emission Unit Description	ID	Emission Unit Description
018	Central vacuum system No. 1	**045**	Powdered sugar dryer/cooler, packaging Line 8A and 8B
019	Sugar packaging Lines 0-9, including 8A and 8B	**046**	Powdered sugar hopper
020	Sugar grinder	**047**	Sugar packaging lines (12-14)
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)	**049**	Baghouse (Currently inactive).
031	Railcar sugar unloading receiver No. 1		
032	Railcar sugar unloading receiver No. 2		

PROJECT DESCRIPTION

The purpose of this project is to revise the existing Title V air operation permit No. 0990005-034-AV for the above referenced Sugar Refinery and Transshipment facilities to incorporate minor revisions from air construction permit Nos. 0990005-035-AC.

PROCESSING SCHEDULE AND RELATED DOCUMENTS

0990005-017-AV Effective Date: July 17, 2010
0990005-032-AV 1st Revision Effective Date: September 11, 2012
0990005-033-AV 2nd Revision Effective Date: October 11, 2012
0990005-034-AV 3rd Revision Effective Date: August 29, 2013
0990005-038-AV 4th Revision Effective Date: *DRAFT/PROPOSED*

PRIMARY REGULATORY REQUIREMENTS (TOTAL FACILITY)

Standard Industrial Classification (SIC) Code: 2062 – Sugar Refinery

North American Industry Classification System (NAICS): 311312

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

Title IV: The facility does not operate units subject to the acid rain provisions of the Clean Air Act.

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

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

The facility is subject to Chapter 62-17, F.A.C. for power plant site certification because it produces more than 75 MW of steam-generated electrical power. [Site Certification No. PA 04-46]

Existing units are subject to the following New Source Performance Standards (NSPS) in Part 60 of Title 40, the Code of Federal Regulations (CFR): Subpart A (General Provisions), NSPS Part 60, Subpart Da (Electric Utility Steam Generating Units).

Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A General Provisions.

Units are subject to 40 CFR 63 Subpart DDDDD-National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. [Rule 62-213.440, F.A.C.] *Appendix SS provides a summary of the applicable requirements for each regulated unit.*

Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A – General Provisions.

REGULATED POLLUTANTS

Criteria Pollutants

Emissions units at this facility may emit one or more of the following criteria air pollutants: carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM_{10}), volatile organic compounds (VOC) and lead (Pb).

Other Regulated PSD Pollutants

In addition to the above criteria air pollutants, emissions units at this facility may emit one or more of the following PSD pollutants: fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; and mercury (Hg).

Hazardous Air Pollutants

Emissions units at this facility may emit one or more hazardous air pollutants (HAP) as defined in Rule 62-210.200, F.A.C.

PROJECT REVIEW

This project revises the existing Title V air operation permit No. 0990005-034-AV for the above referenced facility to incorporate minor revisions from air construction permit Nos. 0990005-035-AC to add a baghouse to the Bulk Load-out Operation (EU-034) and 0990005-037-AC and add four (4) Sugar Packaging Lines No. 16, 17, 18 and 19 with baghouse, to Warehouse No. 3.

CONCLUSION

This project revises Title V air operation permit No. 0990005-034 -AV, which was effective on AUGUST 26, 2013. This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statues (F.S.), and Chapters 62-4, 62-210, 62-213 and 214, F.A.C.

ASH MANAGEMENT PLAN

This Appendix identifies and describes the practices for managing, sampling, and analyzing ash generated from the boilers operating at this plant. Enforceable "permit conditions" are specified at the end of this Appendix.

Ash from Bagasse and Wood Combustion

Bottom Ash

Bottom ash is discharged continuously from each boiler into three, water-submerged drag chain conveyors. Each conveyor consists of a wet upper compartment and a dry lower compartment. The upper compartment has a water-tight steel trough designed to contain the water required for quenching and cooling the bottom ash to 140º F and is sized to accommodate and store up to two hours of bottom ash generated from the wood or bagasse.

The submerged chain conveyor has a removal rate of 8 TONS/HOUR (TPH). An integrated water supply and recirculation system is used. Over flow water from the submerged dry chain conveyor trough, hopper seal trough, and dewatered ash storage pile is piped back to a recirculation sump equipped with an overflow weir and a return sump pump. Make-up water is added to the recirculation sump to replace water lost in the dewatered ash and through evaporation. The bottom ash in then transferred to an enclosed mixed ash belt conveyor for transfer to the mixed ash bunker.

Fly Ash

Fly ash consists of ash collected in air heater hoppers, dust collector hoppers, and from ESP hoppers. Fly ash is transferred by screw conveyors from each system and is wetted prior to transfer to the enclosed mixed ash belt conveyor that transfers it to the mixed ash bunker. All of the fly ash and dust collector ash conveyors are enclosed.

Mixed Ash Bunker

The mixed ash bunker is a 3-sided bunker sized to accommodate about a seven-day ash capacity. At this point the ash is extremely wet. Under normal operating procedures, the ash is removed from the bunker in a wetted condition. If it is determined that the bottom ash in storage has become dry, it will be sprayed with water. A front-end loader is used to reclaim and load the stored ash into trucks.

Ash Disposal

All ash generated by the facility is taken to a Class I landfill for disposal.

Quality Control Measures

Samples of mixed bottom and fly ash are obtained from the storage bunker weekly for four weeks. Each weekly sample is a composite of mixed ash grab samples from three to five locations of the ash piles in the storage bunker. After collection of the composite sample in the fourth week, the monthly sample is prepared for analysis by mixing equal portions of the four weekly mixed ash samples. A portion of the monthly composite mixed ash sample is retained as a control sample for verification of the lab test results, if necessary.

If the fly ash is being collected in the silo, weekly fly ash grab samples are obtained from the transfer point between the collecting fly ash chain conveyor and the bucket elevator conveyor, as ash is loaded into the silo. Additionally, grab samples of the bottom ash are obtained weekly from the bottom ash piles in the storage bunker. The individual sample size for the bottom ash and fly ash grab samples is approximately one pound each.

Prior to releasing the ash samples for outside lab analysis, a "combined ash sample" for the facility is also produced by blending a portion of the individual weekly bottom and fly ash samples (approximately 8, 1 lb samples per month) into a homogeneous composite (fly and bottom ash) ash sample. A portion of the remaining individual fly ash, bottom ash, and combined ash samples is retained on site as control samples for verification of lab test results, if necessary.

The monthly ash samples are analyzed for copper, chromium, and arsenic in accordance with appropriate analytical procedures per 40 CFR 261, Appendix III, described in SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods*. Laboratory results on the sample are typically be available to the plant Environmental Coordinator or Fuels Manager within one week after receipt of the sample at the lab. Any results on the representative monthly composite ash sample which indicate the burning of wood material with concentrations of copper, chromium and/or arsenic above of the air permit limits are investigated by the plant Environmental Coordinator or Fuels Manager. Retesting of the control ash sample will be performed to verify the original lab test results. Comparison of the ash sample results with the corresponding fuel test results will also be performed to ensure that existing material segregation and sampling procedures for the wood material provide for an accurate representation of the composition of the wood material burned at the facility.

Correlation of Wood/Ash Analytical Results

In conjunction with the analytical results of the mixed ash samples, results from the wood samples shall be used to evaluate the effectiveness of the fuel management program in removing chemically treated wood (e.g., copper, chromium and arsenic) from the biomass fuel.

Air Permit Conditions

1. <u>Ash - Sampling and Analysis</u>: At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash (mixed ash) for arsenic, copper, and chromium in accordance with the procedures described in EPA Method SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods* (40 CFR 261, Appendix III). The analytical results from ash testing shall be used in conjunction with those from the as-fired wood samples to evaluate the effectiveness of the fuel management program in removing chemically treated wood from the biomass fuel. The permittee shall dispose of all ash generated on site in accordance with the applicable state and federal regulations. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

2. <u>Ash - Quarterly Reports</u>: Within 30 days following each calendar quarter, the permittee shall submit to the Compliance Authority a summary of the monthly mixed ash analyses and a summary of the ultimate disposal of any off-specification material. [Rule 62-4.070(3), F.A.C.]

Palm Beach County Zoning Requirements for Ash Management

3. The Zoning Plan approved by Palm Beach County requires that New Hope Power Company revise the ash management plan to incorporate the revised testing procedures for the ash as submitted to the Palm Beach County Health Department. The New Hope Power Company must also request that the revised ash management plan be included in the Title V operating permit (Petition DOA 1992-014B and Condition 11 of Resolution R-2004-1372). This Appendix AM of the Title V permit satisfies the County requirement.

Citation Format and Glossary

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF TERMS:

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

AOR: Annual Operating Report

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

BACT: Best Available Control Technology

Btu: British thermal units

CAM: compliance assurance monitoring
CEMS: continuous emissions monitoring system
cfm: cubic feet per minute
CFR: Code of Federal Regulations
CO: carbon monoxide
COMS: continuous opacity monitoring system
DARM: Division of Air 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
EU: emissions unit
F.A.C.: Florida Administrative Code
F.D.: forced draft
F.S.: Florida Statutes
FGR: flue gas recirculation
Fl: fluoride
ft^2: square feet
ft^3: cubic feet
gpm: gallons per minute
gr: grains
HAP: hazardous air pollutant
Hg: mercury
I.D.: induced draft
ID: identification
ISO: International Standards Organization (refers to those conditions at 288 Kelvin, 60% relative humidity and 101.3 kilopascals pressure.)
kPa: kilopascals
LAT: latitude
lb: pound
lb/hr: pounds per hour
LONG: longitude
MACT: maximum achievable technology
mm: millimeter
MMBtu: million British thermal units
MSDS: material safety data sheets
MW: megawatt
NESHAP: National Emissions Standards for Hazardous Air Pollutants
NO_X: nitrogen oxides
NSPS: New Source Performance Standards
O&M: operation and maintenance
O_2: oxygen
ORIS: Office of Regulatory Information Systems
OS: organic solvent
Pb: lead
PM: particulate matter
PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less
PSD: prevention of significant deterioration
psi: pounds per square inch
PTE: potential to emit
RACT: reasonably available control technology
RATA: relative accuracy test audit
RMP: Risk Management Plan
RO: responsible official
SAM: sulfuric acid mist
scf: standard cubic feet
scfm: standard cubic feet per minute
SIC: standard industrial classification code
SNCR: selective non-catalytic reduction
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

Compliance Assurance Monitoring Plan

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1-17 are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables.

40 CFR 64.6 Approval of Monitoring

1. Plans: The attached CAM plans are approved for the purposes of satisfying the requirements of 40 CFR 64.3. [40 CFR 64.6(a)]
2. Contents: The attached CAM plans include the following information:
   a. The indicators to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
   b. The means or device to be used to measure the indicators (such as temperature measurement device, visual observation, or CEMS); and
   c. The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.

   [40 CFR 64.6(c)(1)]
3. Excursions: The attached CAM plans describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see CAM Conditions 5-9) and reporting exceedances or excursions (see CAM Conditions 10-14). [40 CFR 64.6(c)(2)]
4. Required Monitoring: The permittee is required to conduct the monitoring specified in the attached CAM plans and shall fulfill the obligations specified in the conditions below (see CAM Conditions 5-17.). [40 CFR 64.6(c)(3)]

40 CFR 64.7 Operation of Approved Monitoring

5. Commencement of Operation: The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit. [40 CFR 64.7(a)]
6. Proper Maintenance: At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment. [40 CFR 64.7(b)]
7. Continued Operation: Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR 64.7(c)]
8. Response to Excursions or Exceedances:
   a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to

restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) and (2)]

9. Documentation of Need for Improved Monitoring: If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements

10. Triggering a QIP: Based on the results of a determination made under CAM Condition 8.b., above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with CAM Condition 4., an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices. [40 CFR 64.8(a)]

11. Elements of a QIP:

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(i) Improved preventive maintenance practices.

(ii) Process operation changes.

(iii) Appropriate improvements to control methods.

(iv) Other steps appropriate to correct control performance.

(v) More frequent or improved monitoring (only in conjunction with one or more steps under CAM Condition 11.b(i) through (iv), above).

[40 CFR 64.8(b)]

12. QIP Notification: If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the

improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined. [40 CFR 64.8(c)]

13. Revised QIP: Following implementation of a QIP, upon any subsequent determination pursuant to CAM Condition 8.b., the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems; or

b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

[40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. [40 CFR 64.8(e)]

40 CFR 64.9 Reporting And Recordkeeping Requirements

15. General Reporting Requirements:

a. Commencing from the effective date of this permit, the owner or operator shall submit monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.

b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:

(i) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(ii) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(iii) A description of the actions taken to implement a QIP during the reporting period as specified in CAM Conditions 10-14. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 CFR 64.9(a)]

16. General Recordkeeping Requirements:

a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to CAM Conditions 10-14 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to CAM Conditions 10-14 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements. [40 CFR 64.9(b)]

40 CFR 64.10 Savings Provisions

17. Savings Provisions: It should be noted that nothing in this appendix shall:

a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

[40 CFR 64.10]

Units: Cogeneration Boilers (EU-001, 002, and 003)
Pollutant: Particulate Matter (PM)
Standard: PM ≤ 0.026 lb/MMBtu (Opacity limited to ≤ 20%, except for one 6-minute block per hour ≤ 27%)
Control: Mechanical Dust Collectors and Electrostatic Precipitator (ESP)

Parametric Criteria	**Indicator**
Indicator	Opacity
Measurement Approach	Data from the continuous opacity monitoring system (COMS) shall be used to determine potential emissions excursions.
Indicator Range	**An excursion is any 1-hour average of 15% opacity or more.** An excursion requires documentation, investigation, and corrective action.
Data Representativeness	Opacity levels are determined in the stack. A sustained step increase of

	opacity may be related to higher particulate matter emissions resulting from problems with the boiler or control equipment.
QA/QC Practices	The COMS shall be maintained and calibrated in accordance with the applicable requirements of the permit and 40 CFR 60.
Monitoring Frequency	The COMS shall continuously report opacity and determine a 1-hour block average from the average of all valid 1-minute averages collected during the period.
Data Collection Procedures	The COMS shall continuously report opacity and determine a 1-hour block average.
Averaging Period	1-hour block average

OKEELANTA CORPORATION SUGAR MILL AND REFINERY (FACILITY ID NO. 0990005)

In accordance with the supplemental application received on March 12, 2010, the applicant identified the following items for which compliance was not yet determined.

(Note: Boiler No. 16 (EU-014) has been removed and is therefore DELETED per permit No. 0990005-032-AV)

Railcar Receiver No. 1 (EU-031) – (Currently inactive)

Railcar Receiver No. 2 (EU-032)

<u>Permit No. 0990005-023-AC</u>

Deviation: Condition 13 in Subsection 3A requires annual compliance tests for opacity on the associated baghouse vent. The last test was conducted on September 8, 2006 because of lack of operation.

Underlying Cause: It has not been necessary to operate this emissions unit.

Plan: In accordance with the requirements of Rule 62-210.300(5), F.A.C., the permittee shall provide a 60-day advance notification of its intent to restart this unit. The permittee shall conduct the required compliance test within 30 days of restarting the unit.

Rotary Dryer with Rotoclone No. 1 (EU-021)

<u>Permit No. 0990005-021-AC</u>

Deviation: Condition III. 10 of this permit requires initial and subsequent annual compliance tests for opacity. Initial opacity tests were not conducted on the rotary dryer with Rotoclone No. 1 because it was not in operation for the initial tests on equipment at the Transshipment Facility. In addition, this unit has not operated during the current federal fiscal year or the previous two federal fiscal years.

Underlying Cause: The unit has had limited operation.

Plan: In accordance with the requirements of Rule 62-210.300(5), F.A.C., the permittee shall provide a 60-day advance notification of its intent to restart this unit. The permittee shall conduct the required compliance test within 30 days of restarting the unit.

Sugar Packaging Lines 0-9 (EU-019)

Note: In 2011, Okeelanta certified three (3) personnel to perform VE testing to resolve problems. From Feb. 13, 2010 to date, there have been no issues dealing with exceeding the allowable operating rate for this EU-019 based upon the latest testing. The unit was tested at maximum capacity of 1244 tons per year (TPY). Therefore it is determined that the subject of EU-019, is NOT required for this compliance plan..

Common Testing Requirements

Unless otherwise specified by permit, all emissions units that require testing are subject to the following conditions as applicable.

1. 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.]

2. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operating at permitted capacity as defined below. If it is impracticable 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.

   a. *Combustion Turbines*. (Reserved)

   b. *All Other Sources*. 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.]

3. 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.]

4. 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, 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.

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.

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,	Spirometer or calibrated wet test or dry gas test meter	2%

	annually		
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

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

5. 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.]

6. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any 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), toeboard, 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 toeboards.

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 dualrail 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.

7. 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., F.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 in a 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.

8. 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.]

9. The terms stack and duct are used interchangeably in this rule.

   [Rule 62-297.310(9), F.A.C.]

FUEL MANAGEMENT PLAN

This Appendix identifies and describes the practices for managing, sampling, and analyzing authorized fuels at this plant. Enforceable "permit conditions" are specified at the end of this Appendix.

BAGASSE

Description

Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. It is collected and transported by conveyor to the cogeneration plant for use as a fuel in a process which generates both steam and electricity. The mill will supply bagasse to the cogeneration project during the grinding or "crop" season, which is normally from mid-October to April of the following year.

During grinding season, the sugar mill will provide the cogeneration facility with bagasse at an average daily rate of approximately 6,500 tons per day (TPD) and a maximum hourly rate of 270 tons per hour (TPH). The bagasse will be transferred from the mill to the cogeneration facility via the Bagasse Transfer Conveyor, at the design rate of 270 TPH. The Bagasse Transfer Conveyor is equipped with a belt scale designed to monitor and record the rate and quantity of bagasse flowing to the facility. Approximately 50% of the bagasse generated during the grinding season will be fired directly in the cogeneration boilers, while the remaining portion will be stockpiled for use in the off-season.

A system of Chain Distribution Conveyors receive the bagasse at the boiler area and transfer the material to the boiler feeders or to the bagasse bypass and recycle subsystem which conveys the bagasse to a storage area on the site. The fuel from the Chain Distribution Conveyors will be bottom discharged into the boiler feed system via discharge chutes. Each chute is provided with shut off gates which are manually operated.

In the bagasse storage area, front-end loaders are used to reclaim the bagasse fuel and perform pile maintenance. Bagasse fuel is reclaimed from the bagasse storage area by a front-end loader at a design rate of up to 175 tons per hour through the use of one under-pile chain reclaimer. The reclaim conveyor transfers the bagasse to the bagasse Boiler Feed Conveyor that deposits the fuel onto one of two chain distribution conveyors for delivery to the cogeneration boilers.

The entire fuel conveying system is provided with the necessary controls and fire protection systems.

The bagasse pile will be in the location noted on the site plan as fuel storage area. The bagasse will contain moisture in excess of 50%, minimizing the incidence of fugitive emissions. During periods when the pile surface dries out, the pile will be sprayed with water.

The pile will be spread, compacted and rotated to minimize the number of air pockets in the pile and the risk of fire. Also, as explained above, the pile will be dampened when viewed to be dry. During operation of the plant, fuel pile management personnel will be on site 24 hours a day. Telephone communication will be used to contact the local fire department upon the occurrence of a fire incident. The plant operation maintenance manual will incorporate instructions on fire protection and fighting procedure and personnel will be given classroom instructions.

Permit Conditions

1. <u>Bagasse - Sampling and Analysis</u>: At least twice each month, the permittee shall have an analysis conducted on a representative "as-fired" bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon and ash content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), and moisture content (modified ASTM D3173, percent by weight). Samples shall be taken at least two weeks apart. Records of the results of these analyses shall be maintained on site and made available upon request. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

2. Bagasse - Quarterly Report: Within 30 days following each calendar quarter, the permittee shall submit to the Compliance Authority a summary of the analytical results for the "as-fired" bagasse samples taken during the calendar quarter. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]

3. Bagasse - Firing Records: For the Annual Operating Report, the permittee shall calculate the annual bagasse firing rate based on the following: the summation of bagasse delivered from the mill to the cogeneration plant plus bagasse delivered to the bagasse reclaimer scales, minus bagasse measured on the bagasse recycle conveyor to the storage pile. Each value shall be based on the records derived from the in-line belt scale measurements. The total annual heat input rate from steam shall be based on steam production records, the net enthalpy from the steam characteristics, and the boiler thermal efficiencies. The annual heat input from distillate oil shall be based on the gallons of distillate oil fired and the fuel heating values from vendor fuel certifications and sampling/analyses conducted throughout the year. The annual heat input rate from wood shall be determined as described in the next section. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

WOOD MATERIAL

Description

During the non-grinding season, normally from April to mid October, the bagasse is no longer produced as a fuel and clean wood material is used as the primary biomass fuel. During the non-grinding season, bagasse is reclaimed from the bagasse storage pile and fed to the boilers to ensure consistent operations. Wood waste will be delivered to the facility by trucks at an approximate design rate of 3,600 tons per day. The anticipated deliveries are 6 days per week, 12 hours per day. Each truck is anticipated to have a capacity of 25 tons of wood material.

Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter.

The permittee is required to design and implement a management and testing program for the wood material and other materials delivered to the plant for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. The program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. Fuel scheduled for burning shall be inspected daily.

The trucks will be unloaded either by utilizing two hydraulically operated truck dumpers or by means of an unloading area provided to accommodate self-unloading trucks. When using the truck dumpers, the wood material will be discharged into three receiving hoppers equipped with chain conveyors which will transfer the wood to the unloading conveyor. The unloading conveyor, which is equipped with a belt scale and a magnetic separator, will convey the wood material to the screen and hog tower at a rate up to the design rate of 300 TPH.

The screen and hog tower is an open facility at which the wood material is discharged onto a disc screen which will separate the material sized less than 3" from the oversized material. The oversized material will be discharged to the hog, which is a motor driven, size reducing piece of equipment which reduces the oversized wood to less than 3”, suitable to feed into the boiler.

The sized wood material is then transferred from the screen and hog tower by a radial stacker to a wood storage area (wood yard) on the site or directed to the boilers via plant feed conveyor, which is equipped with a belt scale for monitoring and recording the quantity of fuel delivered directly to the boilers. The wood is reclaimed continuously at a rate up to the design rates of 175 TPH of wood chips by two under-pile chain reclaimers. The reclaimed fuel is transferred to the cogeneration facility via the wood Boiler Feed Conveyor and to the boiler feeders by the Chain Distribution Conveyors.

The wood delivered will have a relatively high moisture content and, as noted below, only 15% will be less than 1/4” in size. Fugitive emissions will be controlled by water spraying as necessary. The design of the fire protection system for the plant includes a fire water distribution system, designed in accordance with appropriate NFPA standards, including piping, valves and yard hydrants. Hydrants will be located in strategic areas around the fuel storage area at a spacing of approximately 250 feet along the buried yard loop or branch line piping. Hydrants will be suitable for attaching hoses for manual fire fighting. Deluge water spray systems will be used for protection of the fuel handling equipment and the conveyors.

The facility fire hydrant loop is located on the north side of the fuel storage area. The facility also has an auxiliary fire water tank, diesel powered fire water pump and fire hydrant located on the northwest corner of the bagasse fuel storage areas. Water wagons from the sugar mill supplement fire protection on the south side of the bagasse fuel storage area. The facility also utilizes a mobile diesel powered irrigation pump which is used for fire protection in the bagasse fuel storage area.

Quality Control Procedures

The management program for wood material shall be revised as necessary to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. The program provides for the routine inspection and/or testing of the fuel at the originating wood yard sites, as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized.

Wood waste will be supplied to the Project under long-term contracts which include quality requirements reflecting the conditions of the air permit. The wood material specification imposed on the supplier will be:

- Less than 1% by volume or weight shall be plastics, rubber, glass and painted wood.
- Free from chemically treated wood (e.g. chromium, copper and arsenic; creosote; or pentachlorophenol) except for incidental amounts, not to exceed 1% by volume or weight.
- Less than 5% shall be sand, soil or other organic material
- Moisture content shall be between 20% and 50% with a quarterly average of less than 40%.
- 95% shall be less than 4” in size, 15% (on an individual load) will be less than 1/4” in size.

Okeelanta may reject any load which does not meet any one of the above requirements, and the supplier will be required to remove the delivered amount from the site. However, if the wood material exceeds the specification limits for sand, soil, inorganic material or moisture content, Okeelanta may accept the material provided that the supplier reduces its handling and processing costs by a predetermined rate.

Supply Sites

As stipulated in the fuel supply contracts with the wood material suppliers, the delivered wood material must be substantially free of plastics, rubber, glass, and painted wood and contain only incidental amounts of chemically treated wood (e.g., chromium, copper, arsenic, creosote, pentachlorophenol). To help ensure that wood material delivered to the plant meets the provisions of the air permit, as well as other fuel quality specifications, the wood material suppliers will perform inspection and material segregation operations on each load of feedstock received at their facilities. Although the plant will obtain wood material fuel from several different suppliers with a variety of sources for their unprocessed feedstock, the following description of the inspection and material segregation operations are typical of those operations performed at wood yards supplying the plant.

The bulk material feedstock at the originating wood yards will first undergo a “gross” material separation by removing the bulk wood material from other mixed wastes (e.g., plastics, non-wood debris, scrap metal, concrete/soils) through the use of heavy equipment, magnetic separation, and mechanical screening. Trained personnel will be involved in oversight at this level of material segregation such that the majority of prohibited wastes are removed from the bulk wood material. After this operation, the wood material will be further visually inspected and manually sorted (when applicable) to remove unauthorized materials. The “sorted” wood material is then mechanically sized and screened (to actual contract specifications) prior to delivery to the cogeneration plant.

As a quality assurance measure, each fuel supplier’s operations will be periodically reviewed by cogeneration plant personnel during unannounced site inspections. These visits will allow the cogeneration plant to ensure that the supplier’s inspection and segregation efforts remain at acceptable levels.

Wood Fuel Storage Area

The cogeneration plant will periodically sample and analyze the wood materials. Upon delivery of the wood material to the plant, each load will be visually inspected by the Fuel/Ash Handler stationed at the truck receiving dumping area. Loads which contain unacceptable, visible amounts (i.e., greater than fuel contract specified limits) of chemically treated and/or painted wood and other prohibited mixed wastes will be rejected by the inspector and prevented from discharging at the wood fuel storage area. If the delivered load is acceptable based on the visual inspection, the truck will be staged for unloading.

Sampling of the wood material will occur at the wood fuel storage yard. Samples will be taken from specified sections of the wood pile that are representative of the fuel to be reclaimed and burned during the following week of plant operation. The following sampling plan is modeled after the procedures originally specified in NESHAP Subpart DDDDD of 40 CFR 63 (now vacated) for solid fuel-fired industrial boilers. The sampling plan identifies the following steps for sampling and analysis of the wood materials:

- Follow procedures to obtain five grab samples from the fuel pile for the representative composite sample;
- Prepare each composite sample according to the specified procedures; and
- Determine pollutant concentrations for each composite sample.

For each composite sample, identify a minimum of five sampling locations uniformly spaced over the surface of the pile. At each sampling location, take a sample at a depth of approximately 12 to 18 inches. Each grab sample will consist of approximately one gallon of wood chips or about 1.5 lb of wood chips. Each sample will be transferred to clean plastic bags. In general, the grab samples will be used to obtain the composite sample as described below:

- Throughout the sample collection, compositing and delivery to the laboratories, a chain of custody will be used to document sample collection through analysis.
- Thoroughly mix all of the individual grab samples and pour the entire composite sample over a clean plastic sheet.
- Break sample pieces larger than 3 inches into smaller sizes.
- Make a pie shape with the entire composite sample and subdivide into four equal parts.
- Separate one of the quarter samples as the first subset. If a duplicate sample is to be obtained for analysis,

separate a second quarter of the sample as the second subset.

- The sample subset may be ground in a mill or resized using other suitable laboratory methods in order to ensure a uniform size distribution. If a grinding mill is used, care should be taken to avoid metals contamination from the mill (use of a ceramic mill, proper cleaning and sharpening of mill prior to grinding, etc.).
- If the quarter sample is too large, subdivide it further as described above.
- Transfer each sample subset into a clean plastic sealable bag. Document and label each sample appropriately.
- At least one sample subset of the composite sample will be retained temporarily on site for use as a control sample to verify the lab results, if necessary.

The following methods (or equivalent) will be used to analyze as-fired composite wood samples:

- Heating Value reported in Btu/lb (modified ASTM D3286)
- Carbon Content reported in percent by weight, dry (modified ASTM D5373)
- Sulfur Content reported in percent by weight, dry (modified ASTM D4239 method C)
- Moisture Content reported in percent by weight (modified ASTM D3173)
- Copper, Chromium and Arsenic in ppm by weight, dry (Methods 3050/6010, EPA Method SW-846)

The composite samples will be processed by a third party vendor and/or laboratory for required analytical results. It is noted that the National Council for Air and Stream Improvement (NCASI) has identified grinding of biomass samples as a possible point of sample contamination due to the metals contained in the grinding equipment used in labs. Therefore, care must be taken to avoid or minimize metals contamination during the grinding process, including use of a non-metal grinding mill (ceramic, etc.), or use of other resizing methods and proper cleaning, maintenance, and quality control procedures.

Correlation of Wood/Ash Analytical Results

In conjunction with the analytical results of the mixed ash samples, results from the wood samples shall be used to evaluate the effectiveness of the fuel management program in removing chemically treated wood (e.g., copper, chromium and arsenic) from the biomass fuel. Results that indicate contamination of the wood fuel by copper, chromium, and/or arsenic in concentrations that exceed the specified limits in the air permit, will be investigated by the Environmental Coordinator, Shift Supervisor and/or Fuels Manager. Additional sampling, analysis and/or testing will be performed to determine the extent of the contaminated wood fuel.

Records

Records of the various wood material inspections and wood fuel and sampling and analysis procedures outlined in this Plan will be maintained at the plant for review on an as-requested basis by the Compliance Authority. The records will typically include: fuel delivery information (e.g., supplier, time/date of delivery, type of material, delivery size); written inspection reports of periodic unannounced site visits to wood fuel suppliers; and wood material and ash sampling and analysis information (e.g., time/date of sampling, locations selected for sampling, any atypical conditions, labs utilized, sample results). These records may also be used by plant personnel in investigating potential non-compliance events and verifying fuel test results.

Palm Beach County Provisions

The Zoning Plan approved by Palm Beach County requires that New Hope Power Company revise the fuel management plan to incorporate the "Inclement Weather Operating Procedures" and "Wood, Bagasse, and Ash Inspection and Testing Plan" as submitted to the Palm Beach County Health Department. New Hope Power

Company must also request that the revised fuel management plan be included in the Title V operating permit (Petition DOA 1992-014B and Condition 11 of Resolution R-2004-1372). This Appendix FM of the Title V permit satisfies the County requirement.

Permit Conditions

1. Wood Material - Sampling and Analysis: At least twice each month, the permittee shall have an analysis conducted on a representative "as-fired" wood material sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon and ash content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), moisture content (modified ASTM D3173, percent by weight); copper, chromium, and arsenic (ASTM Methods 3050/6010 or EPA Method SW-846, ppmw, dry). Samples shall be taken at least two weeks apart. Records of the results of these analyses shall be maintained on site and made available upon request. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]
2. Wood Material - Prohibited Materials: Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. [Permit No. PSD-FL-196(P)]
3. Wood Material - Quarterly Report: Within 30 days following each calendar quarter, the permittee shall submit to the Compliance Authority a summary of the following for the calendar quarter: analytical results for the "as-fired" wood material samples taken during the calendar quarter; analytical results that indicate exceedances of the allowable concentrations of copper, chromium, and arsenic; the ultimate disposal of any off-specification material; and a summary of any re-sampling/re-analysis of the wood material performed in the event an exceedance is indicated by the original analysis. [Permit No. PSD-FL-196(P); Rule 62-4.070(3), F.A.C.]
4. Wood Material - Firing Records: The permittee shall track the amount of wood chips delivered to the site and the amount of wood chips fired in the cogeneration boilers. The total annual heat input rate from firing wood chips shall be calculated based on the annual firing rate and the measured heating values as determined from the sampling and analyses conducted throughout the year. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

DISTILLATE OIL AND NATURAL GAS

Description

Distillate oil and natural gas are fired as startup/supplemental fuels in the cogeneration boilers and as the primary fuels for Boiler 16. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05% by weight. Each boiler may startup solely on natural gas or distillate oil. The firing of all fossil fuels (distillate oil and natural gas) shall be less than 25% of the total heat input to each cogeneration boiler during any calendar quarter.

The fuel oil system consists of a truck unloading facility, a 50,000 gallon fuel oil storage tank, two fuel oil transfer pumps, a fuel oil dispensing station, and associated piping, valves, and instrumentation. The fuel oil will be stored in an enclosed tank surrounded by a berm, which is sized to contain the full capacity of the tank in the event of a spill. The tank will be located at a distance from the plant in accordance with the NFPA separation requirements. The area around the fuel tank will be serviced by hydrants connected to the fire system yard loop. Any spilled oil will be collected and taken off-site for proper disposal.

Permit Conditions

1. Oil - Sampling and Analyses:
   a. For each oil delivery, the permittee shall record and retain the date, the gallons delivered, heating value and a certified fuel oil analysis from the vendor identifying the sulfur content (percent by weight) and

identification of the test method used.

b. The following methods are approved analytical methods for determining these characteristics: ASTM Method D-129, ASTM D-1552, ASTM D-2622, and ASTM D-4294. Other more recent or equivalent ASTM methods or Department-approved methods are also acceptable.

c. At least once during each federal fiscal year, the permittee shall have a representative sample taken from each oil storage tank and analyzed in accordance with the authorized methods. Results of the analyses shall be retained on site and made available for inspection upon a request from the Compliance Authority.

[Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

2. Oil - Firing Records: For the cogeneration units, the permittee shall observe the oil flow meter and record the amount oil fired for each calendar quarter within 10 days of the end of each quarter. The permittee shall also monitor and record the annual oil firing rate from the cogeneration units and Boiler 16 for use in filing the Annual Operating Report. The total annual heat input rate from oil firing shall be calculated based on the annual firing rate and the measured heating values as determined from the sampling and analyses conducted throughout the year. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

3. Natural Gas - Records: The permittee shall monitor and record the amount of natural gas combusted in each boiler on a quarterly basis within 10 days of the end of each month. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

Good Combustion Plan, Cogeneration Boilers

General Procedures

Emissions of CO, PM/PM_{10}, and VOC shall be minimized by ensuring efficient combustion through the proper application of good combustion practices (GCPs). Operators will implement following measures to promote good combustion in each cogeneration boiler.

1. Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
2. Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
3. Mix biomass fuel to provide a consistent fuel blend.
4. Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
5. When necessary to enhance poor combustion, reduce the biomass fee rate below the maximum rate.
6. When necessary to enhance poor combustion, co-fire natural gas or distillate oil.

Specific Procedures

For each cogeneration boiler, operators will observe the following practices to provide reasonable assurance that GCPs are being employed. These actions may be performed by the operator or other personnel under the operations manager's supervision. The information collected shall be reported to the operations manager.

1. Operators will maintain an optimal steam production rate by controlling the biomass fuel feed into the boiler.
2. Operators will provide sufficient combustion air to promote good combustion.
3. Operators will periodically view the boiler control instrumentation to confirm that good combustion is taking place. If abnormal combustion is observed, the operator will immediately take corrective action. The control room operator will log the occurrence and duration of all such events in the boiler operation log, along with the corrective action taken.
4. At least twice per shift, operators will examine the boiler grates for proper fuel distribution and make appropriate adjustments. Unusual observations will be logged.
5. At least once per shift, operators will perform a walk-around inspection of the boiler to check the following: fans, pumps, casing, ducting, control equipment, and monitoring equipment. Adjustments and repairs will be performed as necessary.
6. At least once per shift, operators will inspect the fuel feeders and clean as necessary.
7. Operators will use the installed oxygen meter for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor will be used with automatic feedback and/or manual controls to continuously optimize the air-to-fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator will provide sufficient excess air to ensure good combustion within the boiler. The instrument readouts are located in the boiler control room to provide real time data to the control room operator, and display the instantaneous and the historical average. The control room operators are instructed in the use of the O_2 flue gas process monitor for combustion control. The control room operator will periodically observe the oxygen content and adjust boiler operations consistent with GCPs. The CO and NOx CEMS are set to alarm whenever:
   a. Measured NO_X emissions exceed the allowable emission rate (0.15 lb/MMBtu as a 30-day rolling average); and
   b. Measured CO emissions exceed the allowable CO emission rate (0.50 lb/MMBtu as a 30-day rolling average and 0.35 lb/MMBtu as a 12-month rolling average).

   When an alarm is activated, the control room operator will take corrective action and adjust boiler operations consistent with GCPs. Corrective actions include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, or firing some fuel oil or natural gas in place of biomass. Corrective actions continue until the O_2, NO_X, and/or CO flue gas concentrations are returned to acceptable levels.

Use of Flue Gas Oxygen Monitor as BACT for Combustion Controls

The permittee shall install, operate and maintain a flue gas oxygen monitor that meets the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. Using the certified CO and NO_X CEMS data, the permittee shall determine the influence of the flue gas oxygen content on CO and NO_X emissions throughout the range of typical operating loads. As necessary, the permittee shall adjust the flue has oxygen content in the boilers to control CO and NO_X within the permitted emissions standards.

ARMS ID. No. 0990005 – Okeelanta Corporation, Sugar Mill and Refinery

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
014	*DELETED - Mill Boiler No. 16*			
015	*DELETED - Fuel Storage Tank*			
016	*DELETED - Fuel Storage Tank*			
017	*DELETED - Fuel Storage Tank*			
018	Central Vacuum System			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Modification	0990005-004-AC	07/11/2000	07/11/2005
	Modification, expansion	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
019	Packaging Lines, including 8A and 8B			
	Initial (After-the-Fact) Construction	0990005-001-AC	01/26/1996	01/26/2001
	Modification	0990005-004-AC	07/11/2000	07/11/2005
	Modification	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
	Modification	0990005-023-AC	01/16/2009	01/15/2010
020	Sugar Grinder and Hopper			
	Initial (After-the-Fact) Construction	0990005-001-AC	01/26/1996	01/26/2001
	Modification	0990005-004-AC	07/11/2000	07/11/2005
	Modification	0990005-008-AC	05/10/2001	05/10/2006

ARMS ID. No. 0990005 – Okeelanta Corporation, Sugar Mill and Refinery

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
021	Rotary Dryer, Central Dust Collection System No. 1 with Rotoclone No. 1			
	Initial (After-the-Fact) Construction	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
022	Central Dust Collection System No. 2 with Rotoclone No. 2			
	Initial (After-the-Fact)	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
023	Cooler No. 1 with Rotoclone No. 3			
	Initial (After-the-Fact)	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
024	Cooler No. 2 with Rotoclone No.4			
	Initial (After-the-Fact)	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
025	Fluidized Bed Dryer/Cooler with Baghouse			
	Initial	0990005-002-AC	7/18/1996	07/18/2001
	Construction	0990005-005-AC	01/19/2001	01/19/2006

ARMS ID. No. 0990005 – Okeelanta Corporation, Sugar Mill and Refinery

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
026	Sugar Silo (S1101)			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Construction	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
027	Sugar Silo (S1102)			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Construction	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
028	Sugar Silo (S1103)			
	Initial (After-the-Fact)	0990005-001-AC	01/26/1996	01/26/2001
	Construction	0990005-008-AC	05/10/2001	05/10/2006
	Concurrent Modification w/Permit No. 0990005-012-AV	0990005-013-AC	11/13/2003	08/22/2006
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
031	Railcar Sugar Unloading Receiver No. 1			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
032	Railcar Sugar Unloading Receiver No. 2			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
034	Bulk Load-Out Operation			

ARMS ID. No. 0990005 – Okeelanta Corporation, Sugar Mill and Refinery

EU ID No.	Description	Permit Nos.	Issue Date	Exp. Date.
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
035	Transfer Bulk Load-Out Station			
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
043	Sugar Refinery Alcohol Usage			
	Construction	0990005-005-AC	01/19/2001	01/19/2006
	Modification, Expansion	0990005-021-AC	01/15/2008	02/25/2008
045	Powdered Sugar Dryer/Cooler, packaging Lines 8A and 8B			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
	Modification	0990005-023-AC	01/16/2009	01/15/2010
046	Powdered Sugar Hopper			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
047	Sugar Packaging Lines (11-14)			
	Modification, expansion	0990005-019-AC	04/11/2006	04/08/2008
	Modification	0990005-023-AC	01/16/2009	01/15/2010
048	Paint Booth			
	Initial Construction	0990005-010-AC	08/22/2001	08/22/2006
	Modification	0990005-015-AC	11/02/2005	11/02/2010
049	Sugar packaging Line 14			
	Initial Construction	0990005-023-AC	01/162009	01/15/2010

	Wet Roto-clone No. 6 – "A" System			
054	*Initial Construction*	*0990005-027-AC*	*05/26/2011*	*05/25/2012*

055	*Wet Roto-clone No. 7 – "C" System*			
	Initial Construction	*0990005-027-AC*	*05/26/2011*	*05/25/2012*
N/A	*EXEMPT – Temporary Portable Jaw Crusher*	*0990005-028-AC*	*06/17/2011*	*N/A*
N/A	*EXEMPT – Packaging Line 10 Baghouse*	*0990005-029-AC*	*07/06/2011*	*N/A*
N/A	*EXEMPT – Pkg. Line 10 baghouse Administrative Correction*	*0990005-030-AC*	*07/12/2011*	*N/A*
N/A	*EXEMPT – Temporary Portable Jaw Crusher*	*0990005-031-AC*	*12/15/2011*	*N/A*
All	*Title V Permit Revision*	*0990005-032-AV*	*09/12/2012*	*07/16/2015*
All	Administrative Correction to Permit No. 0990005-032-AV	*0990005-033-AV*	*10/10/2012*	*07/16/2015*
All	*Title V Permit Revision*	*0990005-034-AV*		*07/16/2015*

ARMS ID. No. 0990332 – New Hope Power's Okeelanta Cogeneration Plant

EU ID No.	Description
001	Cogeneration Boiler No. A
002	Cogeneration Boiler No. B
003	Cogeneration Boiler No. C
004	Cogeneration Plant - Material Handling and Storage
005	Cogeneration Plant – Miscellaneous Support Equipment

Description	Permit Nos.	Issue Date	Exp. Date.
Initial air construction permit (AC50-219413)	AC50-219413 (PSD-FL-196)	09/27/1993	07/01/1996
Extension of initial air construction permit	AC50-219413 (PSD-FL-196)	---	Unknown
Modified to add limit of 30% yard trash (NSPS Subpart Ea)	0990332-001-AC (PSD-FL-196A)	02/20/1996	04/01/1997
1st Extension for simultaneous operation with mill boilers	0990332-002-AC (PSD-FL-196B)	06/14/1996	04/01/1997
Temporary permit to conduct trial burn of TDF (expired)	0990332-003-AC (PSD-FL-196C)	01/22/1997	12/31/1998
Modified SAM test method	0990332-004-AC (PSD-FL-196D)	04/18/1997	12/31/1998
2nd Extension for simultaneous operation with mill boilers	0990332-005-AC (PSD-FL-196E)	04/05/1997	04/01/1998
Modified of CO, Pb, and Hg standards	0990332-006-AC (PSD-FL-196F)	10/24/1997	07/01/1998
Modified performance test schedule (Specific Condition #11)	0990332-007-AC (PSD-FL-196G)	05/08/1997	04/01/1998
Withdrawn	0990332-008-AC (PSD-FL-	09/15/1997	Withdrawn

	196H)		
3rd Extension for simultaneous operation with mill boilers	0990332-009-AC (PSD-FL-196I)	06/15/1998	04/01/2001
Modified CO standard	0990332-010-AC (PSD-FL-196J)	06/24/1999	04/01/2001
4th Extension for simultaneous operation with mill boilers	0990332-011-AC (PSD-FL-196K)	11/16/2000	10/01/2002
Modified to add mechanical dust collectors before ESP	0990332-012-AC (PSD-FL-196K)	12/22/1999	10/01/2002
Modified to add natural gas as startup/supplemental fuel	0990332-013-AC (PSD-FL-196L)	01/24/2001	10/01/2002
Modified CO, Fl, Pb, Hg, SO_2, and SAM standards	0990332-014-AC (PSD-FL-196M)	01/31/2002	10/01/2002
Modified electrical generation basis from “gross” to “net”	0990332-015-AC (PSD-FL-196N)	05/01/2001	10/01/2002
Modified maximum heat input rate to 760 MMBtu per hour	0990332-016-AC (PSD-FL-196O)	10/27/2003	09/01/2004
Modified to add 65 MW steam turbine electrical generator	0990332-017-AC (PSD-FL-196P)	06/06/2005	12/15/2006
Modified to add four natural gas burners Boiler A	0990332-019-AC	06/06//2012	12/31/2012
Modified of ACI Requirement for Boilers A, B and C.	0990332-020-AC (PSD-FL-196Q)	07/13/2012	

NEW HOPE POWER COMPANY (Facility ID No. 0990332)

Permit No. PSD-FL-196 (as modified) requires the permittee to develop and maintain operation and maintenance plans (O&M) for the cogeneration boilers and pollution control equipment. To the extent practicable, plant personnel will follow the procedures identified in this O&M plan to ensure good operation and control of emissions. Operation outside of the specified range for any monitored parameter would not be a violation by itself. However, continued operation outside of a specified operating range without corrective action may be considered circumvention of the air pollution control equipment or methods.

Cogeneration Boilers A, B and C (EUs 001, 002 and 003)

General Description: The cogeneration boilers combust biomass (bagasse and wood) to generate steam and electricity. Distillate oil and natural gas are fired as startup and supplemental fuels. The cogeneration facility supplies the adjacent Okeelanta sugar mill with process steam during the sugarcane grinding season (approximately October through March) and also supplies the associated Okeelanta sugar refinery with process steam year around.

Key Design and Operating Parameters: The key design and operating parameters for the cogeneration boilers are the power generation rate, steam rate, heat input rate, and combustion efficiency. The design rates for these are provided below. The DCS (Distributed Control System) is a computer operated system that continuously monitors the operation of key parameters for the boilers, mechanical collectors, ESPs and SNCR system on each boiler. In addition, this system monitors the CEMs, which measure the boiler flue gas for oxygen and the stack flue gas for SO_2, NO_X and CO. The system will trigger an alarm if any operating conditions are outside of recommended or regulatory ranges.

Capacity: Each cogeneration boiler has a maximum heat input rate of 760 MMBtu/hr when combusting biomass, 400 MMBtu/hr when combusting natural gas, and 490 MMBtu/hr when combusting distillate oil. Each cogeneration boiler has a maximum steam production rate of 506,100 lb/hr at 1500 psig and 975°F. The thermal combustion efficiencies are 68% for biomass and 85% for natural gas and distillate oil. The three cogeneration boilers supply steam to one nominal 75 MW (net) steam-electrical generator and one nominal 65 MW (net) steam-electrical generator.

Good Operating Practices: See Appendix GC of this permit for good combustion practices.

Startup and Shutdown: See Section 3A of this permit for the startup and shutdown plan.

Air Pollution Controls: Particulate emissions are controlled from each boiler by mechanical collectors followed by an electrostatic precipitator. Nitrogen oxide emissions are controlled by the injection of urea in a selective non-catalytic reduction system. Mercury emissions are controlled, as needed, through a carbon injection system and the ESP. These controls are described below in more detail.

Pollutant Emission Rates: The potential annual controlled annual emission rates in tons per year (TPY) for all three cogeneration boilers combined are as follows: 3495 tons/year of CO; 108 pounds per year of Hg; 1498 tons/year of NO_X; 260 tons/year of PM; 260 tons/year of PM_{10}; 37 tons/year of SAM; 599 tons/year of SO_2; and 499 tons/year of vOC.

Mechanical Dust Collectors

General Description: The cyclone dust collectors were supplied by Barron Industries, Model 460 Tube Base III 9K15-2023AU. These are mechanical dust collectors which remove larger PM prior to the ESP. There are 460 cyclone tubes in all.

Capacity: The mechanical dust collectors are designed for a flow rate of 359,506 acfm and an exhaust temperature of 450° F.

Design Efficiency: The mechanical dust collectors are designed for a control efficiency of 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).

Key Design and Operating Parameters and Good Operating Practices: The following parameters are monitored by the DCS for the mechanical dust collectors:

- Operation of ash hopper screw conveyors to monitor if any plugging has occurred.
- Amperage on elevating screw conveyor: if amperage is high, plugging may have occurred and is therefore checked.

In addition, during each outage of the boilers, the dust collector tubes are inspected for damage and wear. Tubes are replaced as necessary.

Electrostatic Precipitators (ESPs)

General Description: Each boiler is equipped with a single ESP for particulate control. Each ESP consists of one chamber with three fields in the direction of flow. Each field has one bus section for a total of three bus sections per chamber. Each bus section is electrically energized by one transformer/rectifier set mounted at the roof level.

Key Design and Operating Parameters: Each ESP is manufactured by Flakt, Inc. with the following design specifications:

- Chambers = 1
- Collecting Plate = 12.30 ft L x 39.37 ft H
- Fields/Chamber = 3
- Specific Collection Area = 200 ft2/1,000 acfm (minimum)
- Gas Velocity = < 4 ft/s
- Pressure Drop = less than 2.8 inches H_2O
- Operating Temperature = 350° F
- Ash Handling = Trough hopper with screw conveyor
- Design Control Efficiency: 98% or greater for particulate matter.

O&M Practices: The ESP is designed as a static piece of equipment employing a minimum of moving parts. The preventative maintenance plan for the ESP includes the following:

Daily

- Each shift, an inspection of the ESP is conducted to check for any unusual conditions that may exist. An operations log sheet is used by plant personnel to record shift operational activities. The log sheet is reviewed daily by the plant operations manager. The following operational parameters are inspected each shift and any unusual conditions are logged:
- All electrical readings of the ESP and related equipment. In addition, any unusual conditions such as circuit breaker trip are recorded and investigated immediately.
- Process operating conditions, including firing rates, steam production (lb/hr), flue gas temperature, and flue gas composition. Any unusual operating conditions are investigated and corrected immediately.
- Gear motors and transformer/rectifiers are checked for oil leaks. Oil leaks are repaired immediately and oil levels are adjusted as necessary.
- Any unusual or excessive noises coming from motors, or control equipment. Any unusual conditions are corrected immediately.
- Inspection of doors / stuffing boxes to detect gas and air leaks.

- In addition, as described above, continuous emission monitor (CEM) data is recorded continuously and is monitored by plant operators. All CEM data for all pollutants (NOx, SO2, CO, and opacity) are stored via electronic files. The ESP operating temperature and transformer/rectifier primary current and voltages are also monitored and recorded continuously. If unusual data is recorded, the source of the problem is investigated and corrected immediately.
- In addition to the daily shift log completed above, the following additional inspections are made, and repairs performed as necessary, on a monthly, quarterly, semi-annual and annual schedule:

Monthly: Clean and inspect the ESP cold roof.

Quarterly

- Stuffing boxes for rapper drives and dampers are adjusted for leaks and replaced if necessary.
- Rapping drive mechanisms are inspected for excessive noise and wear. If out-of-spec operating conditions exist the mechanisms are repaired or replaced.
- Visually check transformer/rectifier for oil level in tank. Oil is added if necessary.

Semiannually: Rapping drive gearmotor oil is sampled and changed, if contaminated.

Annually/During Shut Down

- All ESP internals are inspected.
- Insulators are cleaned and checked for dust, cracks, or evidence of current leakage.
- Transformers/Rectifiers are checked for proper liquid level, dielectric strengths and for formation of deposits.
- If any equipment is not operating within specifications the component will be replaced or repaired.
- During annual ESP shutdown, a thorough inspection of all ESP components is performed. The checklist includes the following ESP equipment:

1. Transformer/Rectifier (T/R) Set
   a. Transformer Liquid
   b. Ground Connections
   c. High Tension Bus Duct
   d. Conduits
   e. Alarm Connections
   f. Ground Switch Operation
   g. High Voltage Connections
   h. Surge Arrestors

2. T/R Control Panel
   a. Wire Terminations
   b. Ground Connections
   c. Circuit Breakers Trip
   d. Mechanism
   e. Meter Terminations
   f. Air Filters, For Cleanliness

7. Gas Distribution Plates
   a. Buildup
   b. Corrosion

8. Inspection Doors
   a. Gasket
   b. Locking Arrangement
   c. Corrosion

9. Through Hopper
   a. Build-up
   b. Corrosion
   c. Leaks
   d. Access Doors

10. Rappers
    a. Seals
    b. Bearings
    c. Clearance to Supports
    d. Shaft Alignment
    e. Free Rotation of

12. Discharge Electrodes
    b. Support Tubes and Insulators
    c. Electrodes
    d. Alignment
    e. Corrosion
    f. Build-up

13. Collecting Electrodes
    a. Supports
    b. Alignment
    c. Corrosion
    d. Buildup

14. Gas Sneakage Baffles
    a. Buildup
    b. Properly Located

15. Screw Conveyors
    a. Lubrication
    b. Gear Box Lubrication

g. Fans

3. Control Panels
    a. Indicator Lights
    b. Locked Cabinets
    c. Meters Recorded

4. Insulator Compartment System
    a. Bushing
    b. Sealings

5. Casing, Nozzles, & Inlet Duct
    a. Buildup
    b. Corrosion

6. Stacks
    a. Buildup
    b. Corrosion

Hammers
f. Shaft Insulators
g. Hammer/Anvil Alignment
h. Inner Arm Wear
i. Hammer Attached

11. Rapper Motors
    a. Motor/Lubrication
    b. Sequencing
    c. Noise
    a.

c. Condition of Screw
d. Pluggage (Inlet & Outlet)
e. Belt Tension

16. Rotary Air Locks
    a. Lubrication
    b. Gear Box Lubrication
    c. Condition of Rotor
    d. Pluggage (Inlet and Outlet)
    e. Belt Tension

Any equipment or component that is not operating properly or is excessively worn is replaced or repaired prior to ESP operation.

Selective Non-Catalytic Reductions (SNCR) System

General Description: A urea injection system manufactured by Nalco-FuelTech is installed for NO_X control. The technology is a selective non-catalytic reduction (SNCR) process, which reduces NO_X emissions through chemical reactions with urea. In this process, urea is injected into the flue gas stream and reacts with NO_X to form nitrogen and water vapor. The NOx control system includes the following major components: carrier air compressors, urea tank, urea/air flow controls, control panel, injection manifolds, injectors, valves and instrumentation. A single urea storage tank system supplies urea to the boilers. Two injection zones are used to provide injection at full and part load conditions. The first zone has six injectors and the second zone has six injectors, for a total of twelve injectors per boiler. Zone switching valves direct the urea/carrier mixture to the appropriate injection zone.

Key Design and Operating Parameters: The urea injection system is designed to meet a maximum NO_X emission rate of 0.15 lb/MMBtu when firing biomass or No. 2 fuel oil. At maximum capacity, the Urea injection rate is approximately 65 GPH and the ammonia slip may be as high as 25 ppmvd. The NOx design removal efficiency is 40%.

O&M Practices:

Each shift, the plant operator completes an inspection of the urea injection system. The inspection includes the urea pressure, urea flow and air pressure for each injector. Once per shift, the air and chemical valves are closed simultaneously to check each injector for fouling. Pressures and flows are adjusted as necessary. At a minimum of once per week the injector nozzles are inspected and cleaned. Any unusual conditions are repaired and noted.

The urea metering module and urea circulation modules are also inspected once per shift. The operating conditions recorded on the metering module for each boiler include dilution water pressure, NO_X pump in service, NO_X gallons per minute, water pump flow, and water pump discharge pressure. The urea circulation module parameters recorded on a shift basis include the urea tank level, circulation pump condition, and the strainer differential pressure. If any of the parameters listed above are not operating within the normal range, repairs are initiated and recorded in the logbook. The logbook is reviewed daily by the plant operations and maintenance manager.

Injectors

- The distribution module flows and pressures are inspected at least once per shift.
- The injectors are pulled from the boiler and cleaned of built up scale on a weekly schedule.
- During injector cleaning the chamber cap and atomization chamber are removed and the orifices inspected and cleaned to assure that partial plugging has not occurred.

Mechanical Components: Bi-annually a general inspection of mechanical components is performed to check for evidence of corrosion, loosening or shifting parts due to vibration or wear, or any evidence of overheating. Any component showing evidence of damage, breakage, or wear is replaced.

Circulation and Water Boost Pumps: Visual inspections are performed on a daily basis looking for early signs of wear and/or failure of pump and seal components. If a defective part is discovered, the mechanical component is replaced.

Metering Pumps:

- Visual inspections are performed on a daily basis looking for early signs of wear and/or failure of the metering pump and seal components. If a defective part is discovered, the mechanical component is replaced.
- The drive housing oil is changed when contaminated.
- The metering pump DC motor and DC drive are checked monthly.

Valves: On at least a weekly basis each valve is exercised fully open and closed and checked for proper operability and leak tightness. Packing, seals, ball valves and other valve components are replaced if signs of wear are found.

<u>Regulators</u>: Upon discovery of erratic regulator operations the regulators are cleaned. Erratic regulator operations are usually caused by dirt accumulation in the disk area.

Strainers: Strainer baskets on the circulation module and metering module are replaced when wear becomes evident. The baskets are cleaned when the pressure differential across the strainer is greater than five (5) psig.

Pressure and Temperature Indicators: On each shift, the pressure indicator is inspected for soundness and validity. If the instrument is suspect, the equipment is either recalibrated or replaced as necessary. Each instrument is calibrated a regular basis. The pressure indicators have a root valve that can be closed to isolate the pressure indicator from the system. The indicator can then be removed for calibration without shutting the system down.

Flow Meters: On each shift, the flow meter is checked for soundness and validity. If the instrument calibration is suspect, the flow indicators are re-calibrated or replaced. Periodically, the electrical and mechanical fitting are inspected for looseness or separation. If an out-of-spec condition exists the problem is corrected or the component is replaced.

Metering Module Control Panels: The panel is maintained free of dirt and cleaned periodically. Occasional blowing out with dry air is performed on the panels. All control panel devices (i.e., timer, relay, contactor, lamp or other device) are inspected and if found to be defective are replaced.

<u>Alternate NOx Emissions Control Plan</u>

This alternate NO_X control plan identifies the minimum urea injection rate that has demonstrated continuous compliance with the NO_X emissions limit at various load conditions. The purpose of this plan is to monitor compliance with the NO_X standards when the CEM for NO_X is not operating. If a CEM for NO_X is out of service, New Hope Power Company will continue to inject urea at a rate consistent with the other operating boilers. This rate is generally in the range of 50 to 75 gal/hr of urea per boiler. If a monitor goes out of service, and no other boiler is operating, New Hope Power Company will continue to inject urea into the boiler at the injection rate that existed just prior to the monitor outage. It is noted that historically, the NO_X monitors at New Hope Power Company have had downtimes of less than 1 percent. As a result, the alternative NO_X monitoring plan will likely be utilized very infrequently in the future.

Activated Carbon Injection – Mercury Control System

General Description: The mercury control system consists of a volumetric feeder with an integral supply hopper that meters activated carbon for flue gas injection. The injection point is located between the boiler and the ESP. A blower system transports the carbon to the injection point. The ESP effectively captures the activated carbon particles along with boiler flyash (which contains some carbon). The system is designed to inject up to 13 lb/hr of activated carbon into the flue gases of each boiler. The activated carbon is manufactured specifically for removal of heavy metals and mercury contaminants found in exhaust gases. It is also effective for adsorption of dioxins and other incomplete combustion byproducts. The activated carbon is a free flowing powdered carbon with minimal caking tendencies, which makes it ideal for automatic carbon injection systems. It is manufactured with a high ignition temperature to permit safe operations at elevated temperatures. The unique convoluted particle surface provides the maximum reaction surface for rapid removal of gaseous mercury vapors. *{Permitting Note: At the issuance of this permit, the activated carbon system was inactive and the cogeneration units demonstrated compliance with the mercury standard without injecting activated carbon.}*

Key Design and Operating Parameters: The system is designed to inject up to 13 lb per hour of activated carbon into the flue gases of each boiler. Due to the very low mercury emissions from the New Hope Power Company boilers, and the presence of unburned carbon in the flue gas of the boilers, it is not possible to establish a design removal efficiency for the mercury injection system. The carbon feed system consists of the following equipment: storage silo/hopper, feeder motor, feeder gear reducers, feeder vibrator, knifegate valves, educators, solenoid valves, pressure gages, an air line regulator and a strainer/filer. Listed below are operation and maintenance procedures for safe and effective operation of the mercury control system.

O&M Procedures

Normal Activated Carbon Filling Operations

- The hopper is visually inspected for leaks of activated carbon. If leakage occurs, a silicone sealant or stiff epoxy is applied to the area.
- The inside of the hoppers are inspected and any foreign matter present is removed.
- The flexible connector is replaced and the bands are inspected. The knifegate valves above the screw feeders are closed.
- The pressure-vacuum relief valve is closed, and all coupling bolts on the pneumatic valves are inspected for tightness.
- The main panel disconnect is placed in the on position.
- The main control panel hopper low, intermediate, and high level light illumination is inspected.
- The fill line cap from any of the fill lines is removed to energize the dust collector blower. The blower should be running when loading carbon.
- The transfer pressure from truck loading is monitored and should not exceed 10 psig. If excessive pressure

is required to load the hoppers the target boxes and fill lines are checked for an unacceptable accumulation of carbon and cleaned as required.

Blower Checks, Line Pressure, and Flow

- During each shift, the operator checks that the feeder/blower is in service and checks the % feed rate of activated carbon. If the equipment or % feed rate is out of specification, repairs and adjustments are made immediately. In addition, all blower discharge pressure gauges should read approximately 14 psig. If the pressure is less than 14 psig the blower shaft is adjusted and checked against the nameplate speed. More pressure is acceptable; the blower is protected by an inline relief valve. The relief valve is set to 15 psig.
- The flow of air at each line's termination point is checked. Velocities should be approximately 3000 feet per minute and pressures close to atmospheric. If a low velocity is detected, all elements of the line are checked for debris and water.

Feeder Calibration: The CHEMCO screw driver is designed to deliver a minimum of 1.5 pounds of carbon per hour and a maximum of 13 pounds. Periodically, samples of carbon from the feeder discharge spout are collected in order to calibrate the feeder. If necessary, the feeder is recalibrated and/or the malfunctioning equipment is replaced.

Hopper Fluidizing System Checks

- The fluidizing timers within the main control panel are set to a frequency range of 5 to 15 minutes depending on the rate of carbon fed. The higher the feed rate the more frequent the solenoids must be energized to pulse the hopper cones with air.
- The bypass valve must be cracked open and pressurized anytime carbon is in the hoppers.
- Carbon Educators.
- The capability of the educator to ingest solids is dependent upon the position of the nozzle relative to the throat of the educator. The nozzle tip should be pushed in so that it is near the center of the educator suction opening.
- Air admitted to the educator on the screw feed end (suction air) can be controlled using the valves located on the mixing funnel. There are no means provided for measuring the amount of air required for a given feed rate; however, there are two valves provided on the top of each funnel for the purposes of adjusting the suction air flow. The valves may need to be adjusted under certain plant specific operating conditions and both valves should be adjusted to the same setting to prevent an unsymmetrical air-flow into the funnel.

Reactivation Plan: If two or more cogeneration boilers exceed the annual mercury emission limit, the carbon injection system will be activated for all three boilers within 30 days of the stack test report due date.

Quarterly Report, Cogeneration Boilers

<table>
<tr><td colspan="2">Facility Name
Okeelanta Cogeneration Plant</td><td>ARMS ID No.
0990332</td><td>Title V Air Permit No.</td></tr>
<tr><td colspan="4">Facility Address/Location
Located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida</td></tr>
<tr><td colspan="3">Emissions Unit Description
Spreader stoker boiler with maximum heat input of 760 MMBtu/hour
ARMS EU ID No. ______ Cogeneration Boiler: ___ A ___ B ___ C</td><td>Unit Operation in Calendar Quarter
_________ hours</td></tr>
<tr><td colspan="4">Control Equipment
Mercury - activated carbon injection; Nitrogen Oxides – low NOx burners and selective non-catalytic reduction (NOx) system; Particulate Matter – mechanical dust collectors and electrostatic precipitators</td></tr>
<tr><td colspan="3">Primary Fuel
Biomass, which includes bagasse from adjacent sugar mill and wood material from area suppliers (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)</td><td>Auxiliary Fuels
Pipeline natural gas
Distillate oil (≤ 0.05% sulfur by weight)</td></tr>
<tr><td>Pollutant Monitored (Check one.)
_____ CO _____ NOx _____ SO2 _____ Opacity</td><td colspan="3">Calendar Quarter of Operation Covered (Check one.)
___ 1 ___ 2 ___ 3 ___ 4 for year ________</td></tr>
<tr><td>Continuous Monitor Information
Manufacturer:
____
Model No.
____
Date of last certification or audit:
__________________</td><td colspan="3">Emission Standards
_______ lb/MMBtu of heat input, 24-hour rolling avg.
_______ lb/MMBtu of heat input, 30-day rolling avg.
_______ lb/MMBtu of heat input, 12-month rolling avg.
_______ % opacity, except for one 6-minute block per hour ≤ ______ % opacity</td></tr>
<tr><td>Emission Data Summary
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 .... ____</td><td colspan="3">CMS Performance Summary
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 .... ____</td></tr>
</table>

3. [Total duration of excess emissions] x (100%) _ .... [Total source operating time]	2. Total CMS Downtime .... ____ 3. [Total CMS Downtime] x (100%)... ____ [Total source operating time]
Note: Report "excess emissions" as emission averages that are in excess of a permitted emissions standard. For gases, report excess emissions in terms of hours. For opacity, report excess emissions in terms of minutes.	*If monitor availability is not at least 95%, provide a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability*

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startup .... ____
   b. Shutdown... ____
   c. Malfunction .... ____
   d. Total .... ____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to CMS, process or controls during last quarter.

PERMIT SUBSECTION 3A - COGENERATION BOILERS

Facility ID No. 0990332 – New Hope Power's Okeelanta Cogeneration Plant

EU No.	Emissions Unit Description
001	Cogeneration Boiler A
002	Cogeneration Boiler B
003	Cogeneration Boiler C
004	Cogeneration Plant – Material Handling and Storage

Generating Capacity: Two steam turbine electrical generators (75 MW and 65 MW)

Maximum Heat Input Rate: 760 MMBtu/hour (biomass), 605 MMBtu/hour (gas), and 490 MMBtu/hour (oil)

Maximum Steam Rate: 506,100 pounds per hour at 1500 psig and 975°F

Primary Fuels: Bagasse and wood waste (clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter)

Startup and Auxiliary Fuels: Natural gas and distillate oil (≤ 0.05% sulfur by weight)

NO_X Controls: Low-NO_X natural gas burners and a selective non-catalytic reduction (SNCR) system

Particulate Matter Controls: Mechanical dust collectors and an electrostatic precipitator (ESP)

Process Monitors: Maintain continuous monitors for fuel feed rate, heat input, steam production, steam pressure, steam temperature, net power generation, and urea injection rate (as needed).

CEMS: Maintain continuous emissions monitoring systems (CEMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NO_X), opacity, carbon dioxide (CO_2) in lieu of oxygen, and sulfur dioxide (SO_2).

COMS: Maintain continuous opacity monitoring systems (COMS) to measure and record stack opacity.

Restrictions: Operating hours are not restricted. Combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. Combust no wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper. Fossil fuel firing (distillate oil and natural gas) shall be less than 25% of the total heat input to each cogeneration boiler during any calendar quarter.

Emissions Standards Summary:

Pollutant	Averaging Period	Compliance Method
CO	0.50 lb/MMBtu, 30-day rolling avg.	CEMS
	0.35 lb/MMBtu, 12-month rolling avg.	
NO_X	0.15 lb/MMBtu, 30-day rolling avg.	CEMS
SO_2	0.20 lb/MMBtu, 24-hour rolling avg.	CEMS
	0.10 lb/MMBtu, 30-day rolling avg.	
	0.06 lb/MMBtu, 12-month rolling avg.	
Opacity	≤ 20%, except for one 6-minute block per hour that is ≤ 27%	COMS and EPA Method 9

Pollutant	Averaging Period	Compliance Method
PM/PM_{10}	0.026 lb/MMBtu, 3-run test avg.	EPA Method 5 Stack Test
VOC	0.05 lb/MMBtu, 3-run test avg.	EPA Method 25A Stack Test
Mercury	5.4×10^{-06} lb/MMBtu, 3-run test avg.	EPA Method 101A or 29 or 30B

Test Notification: Provide 15 day advance notice of each test.

Test Reports: Submit test report within 45 days after conducting a test.

Annual Tests: Conduct annual stack tests for mercury, PM/PM_{10}, and VOC.

Fuel Records: Maintain a daily log of the amounts and types of fuels used. For each fuel oil delivery, maintain the amount, heating value, and sulfur content. For each calendar month, record the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions.

Quarterly Reports: Within 30 days following each calendar quarter, submit to the Compliance Authority a report summarizing operation of each required continuous emissions and opacity monitoring system in accordance with the requirements specified in the “Quarterly Report” included in Appendix QR of this permit. Report shall also include a summary of the fuel analyses, fuel usage, and equipment malfunctions. For each malfunction, the report shall identify the cause (if known), and corrective actions taken.

Federal Regulations: NSPS Subpart A (General Provisions), Units are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subpart A – General Provisions and 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. [Rule 62-213.440, F.A.C.], Subpart Da (Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978) and NSPS Subpart Ea (Applicability for Standards of Performance for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994)

CAM: PM/PM_{10} emissions controlled by multi-cyclones and ESP

PERMIT SUBSECTION 3B - MATERIAL HANDLING & STORAGE OPERATIONS, COGENERATION PLANT

Facility ID No. 0990332 - New Hope Power’s Okeelanta Cogeneration Plant

EU No.	Emissions Unit Description
004	Material Handling and Storage Operations includes unloading operations, stockpiles, transfer operations, conveyors, screens, crushers, hoppers and silos. Hours of operation are not restricted.

<u>Fly Ash Silo and Activated Carbon Silo</u>:

Controls: Baghouses ≤ 0.01 grains per acfm (design specification for new and replacement bags).

Opacity Standard: Visible emissions ≤ 5% opacity based on a 6-minute average.

Compliance Tests: Conduct EPA Method 9 for opacity annually for each silo that is loaded with ash or carbon.

Test Notification: Provide 15 day advance notice of each test.

Test Reports: Submit test report within 45 days after conducting a test.

CAM: No

Fugitive Dust:

Controls: As necessary, take reasonable precautions to prevent fugitive dust.

PERMIT SUBSECTION 3C - SUGAR MILL & REFINERY

Facility ID No. 0990005 – Okeelanta Corporation Sugar Mill and Refinery

EU No.	Emissions Unit Description
EU-014	*Boiler 16 – DELETED (Permit No. 0990005-032-AV)*

PERMIT SUBSECTION 3D - SUGAR REFINERY

Facility ID No. 0990005 – Okeelanta Corporation Sugar Mill and Refinery

EU No.	Emissions Unit Description
021	*Wet Roto-clone No. 1 (Rotary Dryer)*
022	*Wet Roto-clone No. 2 – "B" System*
023	Cooler No. 1 with Roto-clone No. 3
024	Cooler No. 2 with Roto-clone No. 4
025	Fluidized Bed Dryer/Cooler with Baghouse
034	Bulk Load-Out Operation
035	Transfer Bulk Load-out Station
043	Sugar Refinery Alcohol Usage
054	*Wet Roto-clone No. 6 – "A" System (Permit No.0990005-027-AC)*
055	*Wet Roto-clone No. 7 - "C" System (Permit No. 0990005-027-AC)*

Permitted Capacities: Hours of operation are not restricted. Refined sugar production shall not exceed 490,000 tons/consecutive 52 weeks. Sugar refinery equipment is limited as follows:

- Fluidized Bed Dryer (EU-025) ≤ 490,000 tons of refined sugar/consecutive 52 weeks.
- Rotary Dryer/Cooler System ≤ 130,000 tons of refined sugar/consecutive 52 weeks.
- Bulk Load-Out Operation (EU-034) ≤ 139,000 tons of refined sugar/consecutive 52 weeks.
- Transfer Bulk Load-Out Station (EU-035) ≤ 351,000 tons of refined sugar/consecutive 52 weeks.
- Sugar refinery alcohol usage (EU-043) ≤ 78,040 pounds/consecutive 52 weeks.

Particulate Matter (PM) Emission Standard: The sum of emissions from all emission units shall NOT exceed 22.15 TPY of PM2.5 and 3.00 TPY of PM10.

Opacity Standard: ≤ 5% opacity from each controlled exhaust point (EU-021, 022, 023, 024, 025).

Compliance Tests: Conduct EPA Method 9 for opacity each year for each controlled exhaust point.

Test Notification: Provide 15 day advance notice of each test.

Test Reports: Submit test report within 45 days after conducting a test.

Operational Records: Maintain records sufficient to demonstrate compliance with each permitted capacity.

CAM: No

PERMIT SUBSECTION 3E - TRANSSHIPMENT FACILITY

Facility ID No. 0990005 – Okeelanta Corporation Sugar Mill and Refinery

ID	Emission Unit Description	ID	Emission Unit Description
018	Central vacuum system No. 1	045	Powdered sugar dryer/cooler, packaging Line 8A and 8B
019	Sugar packaging Lines 0-9, including 8A and 8B	046	Powdered sugar hopper
020	Sugar grinder	047	Sugar packaging lines (12-14)
030	Sugar silos Nos. 1, 2, and 3 (Points #1101-1103)	049	Baghouse (Currently inactive).
031	Railcar sugar unloading receiver No. 1		
032	Railcar sugar unloading receiver No. 2		

Permitted Capacity: The maximum sugar packaging rate is 1300 tons/day. Hours of operation of are not restricted.

Controls: All units are controlled by baghouses that must meet the following design specification for new and replacement bags:

$\leq$ 0.0005 grains per acfm for baghouse controlling EU-020

$\leq$ 0.01 grains per acfm for baghouses controlling EU-018, 019, 045, 046, and 047

$\leq$ 0.02 grains per acfm for baghouses controlling EU-030, 031, 032 and 049

Opacity Standard: Visible emissions $\leq$ 5% opacity from each baghouse exhaust point.

Compliance Tests: Conduct EPA Method 9 for opacity annually.

Test Notification: Provide 15 day advance notice of each test.

Test Reports: Submit test report within 45 days after conducting a test.

CAM: No

PERMIT SUBSECTION 3F - DISTILLATE OIL STORAGE TANKS

Facility ID No. 0990332 - New Hope Power's Okeelanta Cogeneration Plant

EU No.	Emissions Unit Description
005	Cogeneration Plant – Miscellaneous Support Equipment

Operational Records: Tanks shall store distillate oil. Maintain records of the types and amounts of fuel stored.

Facility ID No. 0990005 - Okeelanta Corporation's Sugar Mill and Refinery

EU No.	Emissions Unit Description
015	*DELETED - Distillate Oil Storage Tank (29,500 gallons)*
016	*DELETED - Distillate Oil Storage Tank (29,500 gallons)*
017	*DELETED - Distillate Oil Storage Tank (29,500 gallons)*

Operational Records: Tanks shall store distillate oil. Maintain records of the types and amounts of fuel stored.

PERMIT SUBSECTION 3G - PAINT SPRAY BOOTH, FARM OPERATIONS

Facility ID No. 0990005 - Okeelanta Corporation's Sugar Mill and Refinery

EU No.	**Emissions Unit Description**
048	Paint Booth

Permitted Capacity: The maximum throughput rate of paint, thinners and cleanup solvents shall not exceed 4950 gallons/consecutive 12-month period. Hours of operation are not restricted.

Fugitive VOCs: All equipment, pipes, hoses, lids, fittings, etc., shall be operated and maintained in such a manner as to minimize leaks, fugitive emissions, and spills of materials containing volatile organic compounds (VOC).

VOC Emissions: VOC ≤ 9.40 tons/consecutive 12-months

Opacity Standard: ≤ 20% opacity

Operational Records: Maintain monthly records of the following: actual hours of operation of the paint booth; dates of operation; amounts and types of coatings, thinners and cleanup solvents used; and a monthly calculation of VOC/HAP emissions. VOC/HAP emissions shall be calculated by assuming all VOC/HAP in the coatings, thinners and cleanup solvents evaporate. The mass fraction of VOC /HAP from each solvent-containing material shall be determined from the Material Safety Data Sheets (MSDS) supplied by the vendors. The permittee shall maintain a file of MSDS for each solvent-containing material that indicates the composition of the VOC/HAP. Solvent-containing materials include, but are not limited to, powder coatings, solvent coatings, thinners, and cleanup solvents. The file must be maintained on site and made available for inspection upon request. The permittee shall have until the last day of the following month to complete these records.

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.C.

Unregulated and Insignificant Emissions Units and/or Activities

UNREGULATED EMISSIONS UNITS AND/OR ACTIVITIES AND EXEMPTIONS

An emissions unit which emits no “emissions-limited pollutant” and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards. The below listed emissions units and/or activities have been identified by the permittee as “unregulated emissions units”. Emissions units and activities meeting the requirements in Rule 62-213.430(6)(b), F.A.C. are also considered insignificant for purposes of Title V permitting.

Okeelanta Corporation Sugar Mill and Refinery (ARMS ID No. 0990005)

ID No.	EU Description	Activities/Equipment
033	Sugar Refinery Miscellaneous Support Equipment	• Bagging Machines • Bulk Curing, Wet Sugar and Portable Overflow Bins • Centrifugals • De-Sweeteners • Evaporators and Condensers • Large and Small Heaters • Primary and Secondary Filters • Refined Sugar Handling, Storage Silo, and Sugar/Syrup Mixer • Rotex Screens • Silo Scale • Sugar Refinery Process Tanks (Blackwater, Clarifier, Liquor, Melted Sugar Storage, Melter, Mixer, Reactor, Scums, Secondary Treatment, Sweetwater, Syrup Storage Tanks, and Phosphoric Acid Storage and Distribution System • Vacuum Pans with Condenser and non-Condensable Gas Vent • Isopropyl Alcohol Stored in Drums • Powdered Carbon Mixing Room • Refined Sugar Dust Collectors (Vented Inside Building)
036	Shop Activities	• Surface Coating Operations (Non-RACT Vehicle Painting) • Diesel Engine – Portable Air Compressor • Vehicle Repair (Body Shop) • Crawlers Repair Shop • Hydraulic Oil, Mineral Spirits, and Waste/Used Oil Storage Tanks • Mechanics’ Trucks With Portable Air Compressors (Gasoline Engines) • Portable Pressure Cleaners (Gasoline Engines) • Steam Clean Station • Truck, Trailer, Service Vehicles, Wheel Tractor Repair Shops • Cold Cleaning Devices (parts washer) • Containers for Oil/Grease/Used Oil • Oil/Water Separator/Skimmer Equipment • Portable Welders • Pressurized LPG Tanks • Stationary IC Engines • Vacuum Cleaning Systems • Vehicle Generated Dust • Woodworking and Metal Working Operations
037	Sugar Mill Boiler	• Boiler Blowdown Pipes & Vents

Unregulated and Insignificant Emissions Units and/or Activities

ID No.	EU Description	Activities/Equipment
	House	• Boiler Water Chemical Prep Tanks • Boiler Water Dearator and Tank
038	Sugar Mill Cane Dumping Area	• Cane Dumping, Handling, and Storage Cane Knives, Shredding, and Conveying • Steam Clean Station • Oil/Water Separator/Skimmer
039	Sugarcane Processing Facility	• Bagacillo Cyclone and Handling Systems • Batch Mixers (<30 Cu. Ft.) • Carbonaceous Fuel Conveying, Handling and Storage Piles • Cold Cleaning Devices (Non-Halogenated Solvent) • Containers For Oils/Wax/Grease • Cooling Water Towers, Spray Ponds and Canals • Covered Conveyors/Drop Points • Diesel, Gasoline, Fuel Oil, Kerosene, Lube Oil, Waste and Used Oil Tanks • Electric Ovens For Drying • Emergency Generators • Gear Boxes, Reducers Vents • Handling Of Raw Sugar • Industrial Waste Water Tanks (Non-MACT) • Molasses Storage Tanks • Mud Ponds • Oil/Water Separator/Skimmer Equipment • Painting Operations • Portable Diesel Air Compressors • Portable Electric Generators • Portable Welders • Pressurized LPG Tanks • Process Water Filtration Intake Screens • Process Wide Flanges and Valves • Pump Operations • Scrubber Water Ponds and Troughs • Stationary Internal Combustion Engines (General) • Vacuum Cleaning Systems • Vehicle Generated Dust • Vents From Hydraulic/Lube Oil Reservoirs • Woodworking and Metal Working Operations • Centrifugals With Mixers • Crystallizers/Receivers • Evaporator Cleaning Operations • Evaporators (W/ Non-Condensable Gas Vent) • Juice Heaters • Mud Filter Condensers Vacuum Pumps • Process Tanks (Batch, Clarified Juice, Coagulant Mix, Flash, Liming, Mingler, Mixer, Mud Mixing, Pan Feed, Magma, Mud Waste, Muriatic, Sugar Receiver, and Syrup Storage) • Isopropyl alcohol stored in drums • Isopropyl alcohol usage in vacuum pans

Unregulated and Insignificant Emissions Units and/or Activities

ID No.	EU Description	Activities/Equipment
		• Rotary Vacuum Filters • Vacuum Pans with NCG vents, Condensers, And Pumps • Lime Storage Silo and Distribution Systems • Lime Silo Baghouse (5% Opacity) • Diesel Engines for Operation of IWW Pumps • Phosphoric Acid Storage and Distribution Systems • Sodium Hydroxide Storage and Distribution Systems • Mill Crown Wheel Removal Operations • Vertical Molasses Crystallizer • Cane Mills • Cush-cush Screens/Conveyors and DSM Screens • Hydrochloric Acid Tanks • Mill Turbines with Vents • Carbon Slurry Tank • Condensate Tank
040	Facility Fuel Tank Farm	• Diesel, Gasoline and Oil Tanks • Diesel and Gasoline Pumps and Loading Arms • Oil/Water Separator/Skimmer Equipment
041	Facility Potable Water System	• Hydrogen Sulfide Degasifiers • Membrane Cleaning Chemicals and Process Water Discharge Canal • Sulfuric Acid Storage and Distribution Systems • Disinfection System
042	Facility Sewer Plant	• Sewage Treatment Plant • Collection and Distribution Lift Station
044	Okeelanta Facility - Miscellaneous Unregulated Activities	• Forklift and crane operations • Bagasse conveyors to cogeneration boilers or biomass storage.
050	Transshipment Facility, Miscellaneous Support Equipment	• Containers for Oil/Grease/Ink • Diesel Fire Pump Engine • Diesel Tank • Vehicle Generated Dust • Refined Sugar Dust Collectors (Vented Inside Building) • Portable Vacuum Cleaners • Propane-Fired Water Heaters for Disinfection Process Vessels • Steam Clean Station • Cold Cleaning Devices (Parts Washer)

The following activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

056	*Hi-Vac Industrial Vacuum System*	• *Sugar Mill and Refinery*
053	*Printing Operation*	• *Trans-shipment*

The following emission units have been determined by the Department to be EXEMPT from permitting.

057	*Specialty Sugar Product*	• *300 hp gas-fired package boiler (Refined Sugar Warehouse No. 3)*
058	*Sugar Bin with Dust Collector*	• *(Refined Sugar Warehouse # 3)*
052	*Bulk Transfer Station*	• *Wet Roto-clone No. 5*
051	*Refined Sugar Silo*	• *Baghouse*
029	*Packaging Line 10*	• *Baghouse (Located in Sugar Refinery)*

- *Sugar bin with dust collector (refined sugar warehouse #3)**
- *Refined Sugar Silo – Baghouse**
- *Packaging Line 10 Baghouse (Located in Sugar Refinery)**

**These emission units have been determined by the Department to be exempt from permitting.*

New Hope Power Cogeneration Plant (ARMS ID No. 09900332)

ID No.	EU Description	Activities/Equipment
005	Cogeneration Plant - Miscellaneous support equipment	• 50,000 gallon distillate oil tank • Nominal 75 MW Steam Turbine Electrical Generator • Nominal 65 MW Steam Turbine Electrical Generator • Condensers • Two Cooling Towers • Switchyard, etc. • Boiler Drum Blowdown Tank • Diesel Fire Pump Engine • Propane Tank • Hydrogen Sulfide Degasifier • Oil/water Separators • Sodium Hydroxide Tank • Wastewater Neutralization Tank • Cold Cleaning Devices (Parts Washers) • Sulfuric Acid Storage and Distribution Systems • Painting Operations • Portable Diesel Air Compressors • Portable Electric Generators • Portable Welders • Pressurized LPG Tanks • Portable Pumps • Forklift, loader and crane operations

NEW SOURCE PERFORMANCE STANDARDS

Subpart A-General Provisions for 40 CFR 60
[Source: Federal Register dated 7/1/98, Federal Register 5/8/98, 2/12/99, 10/17/00, 6/28/02, 6/1/06]

Cogeneration Boilers (EUs 001, 002 and 003) (Boiler 16 (EU 014) is DELETED)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicable requirements of 40 CFR 60 Subpart A, General Provisions. For these requirements, the original rule numbering has been retained.

40 CFR 60.1 Applicability.

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced
after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).
[40 CFR 60.1(a), (b) and (c)]

40 CFR 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

40 CFR 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

40 CFR 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) Reserved.

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

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

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

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

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

{See Figure 1, Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance, at the end of this section.}

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

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

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

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

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

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

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).
(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.
[40 CFR 60.7(a), (b), (c), (d), (e), (f), (g), (h)]

40 CFR 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).
[40 CFR 60.8(a)]

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.
[40 CFR 60.8(b)(1), (2), (3), (4) & (5)]

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

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems , etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes

(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and

(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

[40 CFR 60.8(e)].

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs. [40 CFR 60.8(f)].

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

40 CFR 60.10 State authority.

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.
[40 CFR 60.10(a) and (b)].

40 CFR 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

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

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.

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

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed

under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.
[40 CFR 60.11(a), (b), (c), (d), (e) and (f)]

40 CFR 60.12 Circumvention.

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

40 CFR 60.13 Monitoring requirements.

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

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continues opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

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

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

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

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

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

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

(g) (1) When more than one continuous monitoring system is used to measure the emissions from only one affected facility (e.g. multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless installation of fewer systems is approved by the Administrator.

(2) When the effluents from two or more affected facilities subject to the same opacity standard are combined before being released to the atmosphere, the owner or operator may either install a continuous opacity monitoring system at a location monitoring the combined effluent or install an opacity combiner system comprised of opacity and flow monitoring systems on each stream, and shall report as per Sec. 60.7(c) on the combined effluent. When the affected facilities are not subject to the same opacity standard applicable, except for documented periods of shutdown of the affected facility, subject to the most stringent opacity standard shall apply

(3) When the effluents from two or more affected facilities subject to the same emissions standard, other than opacity, are combined before released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the continuous monitoring standard, separate continuous monitoring systems shall be installed on each effluent and the owner or operator shall report as required for each affected facility.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners or operators complying with the requirements in Sec. 60.7(f)(1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng or pollutant per J of heat input). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[Rule 62-296.800, F.A.C.; 40 CFR 60.13(h)].

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.
[Rule 62-296.800, F.A.C.; 40 CFR 60.13(i)].

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in section 8.4 of Performance Specification 2 and substitute the procedures in section 16.0 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed
following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards

expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.45(g)(3), 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in section 8.4 of Performance Specification 2.
[Rule 62-296.800, F.A.C.; 40 CFR 60.13(j)].

40 CFR 60.14 Modification.

(a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(a)].

(b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1) . When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions

as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(b)].

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(c)].

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:
(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.
(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.
(3) An increase in the hours of operation.
(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.
(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.
(6) The relocation or change in ownership of an existing facility.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(e)].

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(f)].
(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(g)].

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j) (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration projec*t, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

40 CFR 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(a)].

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(b)].

(c) "Fixed capital cost'" means the capital needed to provide all the depreciable components.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(c)].

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

[Rule 62-296.800, F.A.C.; 40 CFR 60.15(d)].

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(e)].

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:
(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(f)].

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(g)].

§ 60.18 General control device requirements.

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.
(b) *Flares.* Paragraphs (c) through (f) apply to flares.
(c) (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.
(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).
(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.
(i) (A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, Vmax, as determined by the following equation:

$$V_{max}=(X_{H2}-K_1)*K_2$$

Where:
Vmax=Maximum permitted velocity, m/sec.
K1=Constant, 6.0 volume-percent hydrogen.
K2=Constant, 3.9(m/sec)/volume-percent hydrogen.
XH2=The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).
(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.
(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas

being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, Vmax, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, Vmax, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f) (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

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

Eq. 1

where:

HT=Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

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

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}}\right)$ is 20°C;

Eq. 2

Ci=Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

Hi=Net heat of combustion of sample component i, kcal/g mole at 25 >C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, Vmax, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation. Log10 (Vmax)=(HT+28.8)/31.7
Vmax=Maximum permitted velocity, M/sec
28.8=Constant
31.7=Constant
HT=The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, Vmax, for air-assisted flares shall be determined by the following equation.
Vmax=8.706+0.7084 (HT)
Vmax=Maximum permitted velocity, m/sec
8.706=Constant
0.7084=Constant
HT=The net heating value as determined in paragraph (f)(3).

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word ''calendar'' is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be post-marked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the post-mark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

Figure 1. Summary Report
Gaseous and Opacity Excess Emission and Monitoring System Performance

Company: ____

Address: ____

Process Unit(s) Description: ____

Emission Limitation: ____

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting Period Dates: From ________________________ to ____________________________

Total source operating time in reporting period [1]: _________________________

Monitor Manufacturer: ____

Monitor Model No.: ____

Date of Latest CMS Certification or Audit: _____________________________

Emission Data Summary [1]	**CMS Performance Summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions ____
c. Process problems .... ____	c. Quality assurance calibration ____
d. Other known causes .... ____	d. Other known causes ____
e. Unknown causes .... ____	e. Unknown causes ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime ____
3. [Total duration of excess emissions] x (100%) / [Total source operating time] .... ____ % [2]	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.

On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: ____

Signature: ____

Title: ____

Date: ________________

NEW SOURCE PERFORMANCE STANDARDS

Cogeneration Boilers (EUs 001, 002 and 003)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicable requirements of 40 CFR 60 Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for which Construction Is Commenced after September 18, 1978. For these requirements, the original rule numbering has been retained.

§ 60.50a Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each municipal waste combustor unit with a municipal waste combustor unit capacity greater than 225 megagrams per day (250 tons per day) of municipal solid waste for which construction, modification, or reconstruction is commenced as specified in paragraphs (a)(1) and (a)(2) of this section.

(1) Construction is commenced after December 20, 1989 and on or before September 20, 1994.

(2) Modification or reconstruction is commenced after December 20, 1989 and on or before June 19, 1996.

(b) [Reserved]

(c) *{Not applicable.}*

(d) Any cofired combustor, as defined under § 60.51a, located at a plant that meets the capacity specifications in paragraph (a) of this section is not subject to this subpart if the owner or operator of the cofired combustor:

(1) Notifies the Administrator of an exemption claim;

(2) Provides a copy of the federally enforceable permit (specified in the definition of cofired combustor in this section); and

(3) Keeps a record on a calendar quarter basis of the weight of municipal solid waste combusted at the cofired combustor and the weight of all other fuels combusted at the cofired combustor.

(e) Any cofired combustor that is subject to a federally enforceable permit limiting the operation of the combustor to no more than 225 megagrams per day (250 tons per day) of municipal solid waste is not subject to this subpart.

(f) *{Not applicable.}*

(g) A qualifying small power production facility, as defined in section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(h) A qualifying cogeneration facility, as defined in section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy and steam or forms of useful energy (such as heat) that are used for industrial, commercial, heating, or cooling purposes, is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(i) through (k) *{Not applicable.}*

(l) The following authorities shall be retained by the Administrator and not transferred to a State: None.

(m) This subpart shall become effective on August 12, 1991.

§ 60.51a Definitions.

Calendar quarter means a consecutive 3-month period (non-overlapping) beginning on January 1, April 1, July 1, and October 1.

Clean wood means untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), and tree limbs (whole or chipped). Clean wood does not include yard waste, which is defined elsewhere in this section, or construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles), which are exempt from the definition of municipal solid waste in this section.

Cofired combustor means a unit combusting municipal solid waste with non-municipal solid waste fuel (e.g., coal, industrial process waste) and subject to a federally enforceable permit limiting the unit to combusting a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis.

Federally-enforceable means all limitations and conditions that are enforceable by the Administrator including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Municipal solid waste or *municipal-type solid waste* or *MSW* means household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, non-medical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include:

(1) Yard waste;

(2) Refuse-derived fuel; and

(3) Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in § 60.50a(c).

Untreated lumber means wood or wood products that have been cut or shaped and include wet, air-dried, and kiln-dried wood products. Untreated lumber does not include wood products that have been painted, pigment-stained, or ‘‘pressure-treated.’’ Pressure-treating compounds include, but are not limited to, chromate copper arsenate, pentachlorophenol, and creosote.

Yard waste means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance activities associated with yards or other private or public lands. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of MSW in this section. Yard waste does not include clean wood, which is exempt from the definition of MSW in this section.

1. NSPS Subpart Da: The permittee shall comply with the following applicable requirements of 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction

is Commenced After September 18, 1978.

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) *{Not applicable.}*

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41Da Definitions.

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

{Only pertinent definitions have been included

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours.

Cogeneration, also known as "combined heat and power", means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or ESP means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or 40 CFR 51.18 and 40 CFR 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835-87, 91, 97, or 03a (incorporated by reference, see Sec. 60.17).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(a) For particulate matter is:

  (1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

  (2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under Sec. 60.48Da(b).

(c) For nitrogen oxides is:

  (1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

  (2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

  (3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquefied coal, and gasified coal.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42Da Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) and (d) *{Not applicable.}*

§ 60.43Da Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_s = (340x+520\,y)/100$ and

$\%P_s = 10$

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_s = (340x+520\,y)/100$ and

$\%Ps = (10x+30\,y)/100$

where:

Es is the prorated sulfur dioxide emission limit (ng/J heat input),

%Ps is the percentage of potential sulfur dioxide emission allowed.

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

(i) through (k) *{Not applicable.}*

§ 60.44Da Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average, except as provided under § 60.46Da(j)(1):

(1) NO_X emission limits.

Fuel type	Emission limit for heat input	
	ng/J	(lb/MMBtu)
Gaseous fuels: All other fuels	86	0.20
Liquid fuels: All other fuels	130	0.30
Solid fuels: All other fuels	260	0.60

(2) NO_X reduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25%
Liquid fuels	30%
Solid fuels	65%

(b) *{Not applicable.}*

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_n = [86\ w+130\ x +210\ y+260\ z+340\ v]/100$

where:

E_n is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d) through (f) *{Not applicable.}*

§ 60.45Da Standard for mercury.

(a) and (b) *{Not applicable.}*

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) through (e) *{Not applicable.}*

§ 60.48Da Compliance provisions.

(a) Compliance with the particulate matter emission limitation under Sec. 60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under Sec. 60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under Sec. 60.44Da(a) constitutes compliance with the percent reduction requirements under Sec. 60.44Da(a)(2).

(c) The particulate matter emission standards under Sec. 60.42Da, the nitrogen oxides emission standards under Sec. 60.44Da, and the Hg emission standards under Sec. 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) *{Not applicable.}*

(e) After the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitations under Sec. 60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitation under Sec. 60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

  (1) Compliance with applicable 30-day rolling average SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2) only.

  (2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.

  (3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under Sec. 60.49Da of this subpart, compliance of the affected facility with the emission requirements under Secs. 60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

(i) through (p) *{Not applicable.}*

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) *{Not applicable.}*

(3) An “as fired” fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) (1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of Sec. 60.51Da. Data reported to meet the requirements of Sec. 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

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

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) (1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) *{Not applicable.}*

(g) The 1-hour averages required under paragraph Sec. 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under Sec. 60.48Da. The 1-hour averages are calculated using the data points required under Sec. 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

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

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

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

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

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under Sec. 60.13(c) and calibration checks under Sec. 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

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

(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of Appendix B of this part.

(3) *{Not applicable.}*

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

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

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

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under Sec. 60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under Sec. 60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under Sec. 60.42Da, Sec. 60.43Da, Sec. 60.44Da, or Sec. 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of Appendix B and procedure 1 of Appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of Appendix D of 40 CFR part 75.

(o) through (v) *{Not applicable.}*

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the methods in Appendix A of this part or the methods and procedures as specified in this section, except as provided in Sec. 60.8(b). Section 60.8(f) does not apply to this section for SO_2 and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner/operator shall determine compliance with particulate matter standards in Sec. 60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14° C (320 ± 25° F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(3) Method 9 and the procedures in Sec. 60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2 standards in Sec. 60.43Da as follows:

(1) through (3) *{Not applicable.}*

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

(5) The continuous monitoring system in Sec. 60.49Da (b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

(d) The owner or operator shall determine compliance with the NO_X standard in Sec. 60.44Da as follows:

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

(2) The continuous monitoring system in Sec. 60.49Da (c) and (d) shall be used to determine the concentrations of NO_X and CO_2 or O_2.

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

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

(2) The F_c factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of Sec. 60.48(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

(f), (g), (h), and (i) *{Not applicable.}*

§ 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) *{Not applicable.}*

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average

emission rates because of startup, shutdown, malfunction (NO_2 only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by Sec. 60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Sec. 60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i).

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate E_o*) and the upper confidence limit for the mean inlet mission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) and (e) *{Not applicable.}*

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

(g) *{Not applicable.}*

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

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

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

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

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

(i) For the purposes of the reports required under Sec. 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under Sec. 60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A of this part to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X

and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in Sec. 60.45Da or Sec. 60.46Da shall provide notifications in accordance with Sec. 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of Sec. 60.7(f).

NEW SOURCE PERFORMANCE STANDARDS

Cogeneration Boilers (EUs 001, 002 and 003)

In accordance with Rule 62-204.800(8), F.A.C., the cogeneration boilers are subject to the applicability requirements of 40 CFR 60 Subpart Ea, Standards of Performance for Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or Before September 20, 1994. For these requirements, the original rule numbering has been retained.

{Permitting Note: The cogeneration boilers are subject to regulation as Electric Utility Steam Generating Units in accordance with NSPS Subpart Da. The units fire primarily bagasse and wood materials. Permit conditions in Section 3 limit the units to no more than 30% by weight yard waste (yard trash) on a calendar quarter basis, which can be defined as a municipal solid waste (MSW) in 40 CFR 60.51a. As such, the units are not subject to any specific emissions standards or performance requirements imposed by NSPS Subpart Ea.}

§ 60.50a Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each municipal waste combustor unit with a municipal waste combustor unit capacity greater than 225 megagrams per day (250 tons per day) of municipal solid waste for which construction, modification, or reconstruction is commenced as specified in paragraphs (a)(1) and (a)(2) of this section.

(1) Construction is commenced after December 20, 1989 and on or before September 20, 1994.

(2) Modification or reconstruction is commenced after December 20, 1989 and on or before June 19, 1996.

(b) [Reserved]

(c) *{Not applicable.}*

(d) Any cofired combustor, as defined under § 60.51a, located at a plant that meets the capacity specifications in paragraph (a) of this section is not subject to this subpart if the owner or operator of the cofired combustor:

(1) Notifies the Administrator of an exemption claim;

(2) Provides a copy of the federally enforceable permit (specified in the definition of cofired combustor in this section); and

(3) Keeps a record on a calendar quarter basis of the weight of municipal solid waste combusted at the cofired combustor and the weight of all other fuels combusted at the cofired combustor.

(e) Any cofired combustor that is subject to a federally enforceable permit limiting the operation of the combustor to no more than 225 megagrams per day (250 tons per day) of municipal solid waste is not subject to this subpart.

(f) *{Not applicable.}*

(g) A qualifying small power production facility, as defined in section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(h) A qualifying cogeneration facility, as defined in section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy and steam or forms of useful energy (such as heat) that are used for industrial, commercial, heating, or cooling purposes, is not subject to this subpart if the owner or operator of the facility notifies the Administrator of an exemption claim and provides data documenting that the facility qualifies for this exemption.

(i) through (k) *{Not applicable.}*

(l) The following authorities shall be retained by the Administrator and not transferred to a State: None.

(m) This subpart shall become effective on August 12, 1991.

§ 60.51a Definitions.

Calendar quarter means a consecutive 3-month period (non-overlapping) beginning on January 1, April 1, July 1, and October 1.

Clean wood means untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), and tree limbs (whole or chipped). Clean wood does not include yard waste, which is defined elsewhere in this section, or construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles), which are exempt from the definition of municipal solid waste in this section.

Cofired combustor means a unit combusting municipal solid waste with non-municipal solid waste fuel (e.g., coal, industrial process waste) and subject to a federally enforceable permit limiting the unit to combusting a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis.

Federally-enforceable means all limitations and conditions that are enforceable by the Administrator including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Municipal solid waste or *municipal-type solid waste* or *MSW* means household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, non-medical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include:

(1) Yard waste;

(2) Refuse-derived fuel; and

(3) Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in § 60.50a(c).

Untreated lumber means wood or wood products that have been cut or shaped and include wet, air-dried, and kiln-dried wood products. Untreated lumber does not include wood products that have been painted, pigment-stained, or ''pressure-treated.'' Pressure-treating compounds include, but are not limited to, chromate copper arsenate, pentachlorophenol, and creosote.

Yard waste means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance activities associated with yards or other private or public lands. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of MSW in this section. Yard waste does not include clean wood, which is exempt from the definition of MSW in this section.

National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and process Heaters

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7491 was amended by revising paragraph (n). However, there is no paragraph (n) to revise.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 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.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after

January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7495 was amended by adding paragraph (e). However, there is already a paragraph (e).

Emission Limitations and Work Practice Standards

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and process Heaters

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), 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 Administrator that 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.

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

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed 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) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control 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) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation 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 violation 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 violation 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 violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7163, Jan. 31, 2013]

National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and process Heaters

General Compliance Requirements

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS 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);

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

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

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

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013]

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

[78 FR 7164, Jan. 31, 2013]

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013]

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013]

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hm\right) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

Where:

Ave Weighted Emissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 1c)}$$

Where:

Ave Weighted Emissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Sm \times Cfi) \div \sum_{i=1}^{n}(Sm \times Cfi) \quad \text{(Eq. 2)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Hb) \div \sum_{i=1}^{n}Hb \quad \text{(Eq. 3a)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times So) \div \sum_{i=1}^{n}So \quad \text{(Eq. 3b)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \quad \text{(Eq. 3c)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \quad \text{(Eq. 4)}$$

Where:

Ave Weighted Emissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad (Eq.\ 5)$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input 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 boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

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

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategories, each of which vents 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.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n}(ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013]

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(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 PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(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 of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in § 63.8(c)(4)(i), each COMS 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.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.* , PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.* , check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (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) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013]

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

Where:

Mercury input = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \quad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) 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.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least 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.

(*3*) 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 (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an 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 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) 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.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established 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.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu 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.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average 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 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \quad \text{(Eq. 13)}$$

Where:

X_1 = 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.

(D) To determine continuous compliance, 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 (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \quad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) 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 signals corresponding to each PM compliance test run. (iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \qquad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} (TSM90i \times Qi) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013]

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html* .

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \quad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013]

Continuous Compliance Requirements

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, 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 control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is 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. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013]

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

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

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the 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). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the

procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, 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 (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

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

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

(C) Within 30 days of the deviation 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 additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) 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 test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) 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.

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

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

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

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

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

(vi) You must use all the data collected during all boiler or process heater 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.

(vii) 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.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013]

§ 63.7541 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 (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) 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 (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator 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 affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to § 63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013]

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted 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 each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the 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. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using 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 the 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 the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

[78 FR 7183, Jan. 31, 2013]

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(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 tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, 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 § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), 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 relevant pollutant to increase within the past year.

(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013]

§ 63.7560 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, or they must be accessible from on site (for example, through a computer network), 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.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator 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 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 (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) 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, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 7186, Jan. 31, 2013]

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

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.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations 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.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

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 applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; 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.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

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. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits 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 EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, 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.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

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 forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 21)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 22)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 23)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 24)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

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 under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

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. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United 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 their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 [a]lb per MMBtu of heat input	8.7E-07 [a]lb per MMBtu of steam output or 1.1E-05 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Units designed to	a. Filterable	1.1E-03 lb per MMBtu of	1.1E-03 lb per MMBtu	Collect a minimum of 3 dscm

burn coal/solid fossil fuel	PM (or TSM)	heat input; or (2.3E-05 lb per MMBtu of heat input)	of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.

		corrected to 3 percent oxygen, 30-day rolling average)		
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 [a]lb per MMBtu of steam output or 1.2E-03 [a]lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.

		oxygen, 10-day rolling average)		
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 [a]lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.

		average)		
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	5.3E-07 [a]lb per MMBtu of steam output or 6.7E-06 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 [a]lb per MMBtu of steam output or 1.6E-02 [a]lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.

17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables

11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[78 FR 7193, Jan. 31, 2013]

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3	0.14 lb per MMBtu of steam output or 1.7 lb	1 hr minimum sampling time.

fuel		percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	per MWh; 3-run average	
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable	3.2E-01 lb per MMBtu of	3.7E-01 lb per MMBtu	Collect a minimum of 1 dscm

	PM (or TSM)	heat input; or (4.0E-03 lb per MMBtu of heat input)	of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b]collect a minimum of 2 dscm.

15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of	1.4E-05 lb per MMBtu	For M29, collect a minimum

		heat input	of steam output or 8.3E-05 lb per MWh	of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7195, Jan. 31, 2013]

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.

3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.

	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
	If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.
	You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

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[78 FR 7198, Jan. 31, 2013]

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable

	emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2CEMS, maintain the 30-day rolling average SO_2emission rate at or below the highest hourly average SO_2concentration measured during the most recent HCl performance test, as specified in Table 8.

[78 FR 7199, Jan. 31, 2013]

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant...	**You must...**	**Using...**
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.

	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions	Method 19 F-factor methodology at 40 CFR part 60,

	concentration to lb per MMBtu emission rates	appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013]

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

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To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323 [a](for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 [a](for liquid), or ASTM D4057 [a](for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a](for biomass), or EPA 3050 [a](for solid fuel), or EPA 821-R-01-013 [a](for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864 [a], or ASTM D240, or ASTM D95 [a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a](for coal), EPA SW-846-7471B [a](for solid samples), or EPA SW-846-7470A [a](for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.

	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M§[a](for coal), or ASTM D5198§[a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), ASTM D5864, ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864 [a], or ASTM D240 [a], or ASTM D95[a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 [a], ASTM D6721 [a], ASTM D4208 [a](for coal), or EPA SW-846-5050 [a]or ASTM E776 [a](for solid fuel), or EPA SW-846-9056 [a]or SW-846-9076 [a](for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954 [a], ASTM D6350 [a], ISO 6978-1:2003(E) [a], or ISO 6978-2:2003(E) [a], or EPA-1631 [a]or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 [a]or equivalent.
4. TSM for solid fuels	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), or ASTM D4177 [a],(for liquid fuels)or ASTM D4057 [a](for liquid fuels),or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.

	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a]or TAPPI T266 [a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864, or ASTM D240 [a], or ASTM D95 [a](for liquid fuels), or ASTM D4006[a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683 [a], or ASTM D4606 [a], or ASTM D6357 [a]or EPA 200.8 [a]or EPA SW-846-6020 [a], or EPA SW-846-6020A [a], or EPA SW-846-6010C [a], EPA 7060 [a]or EPA 7060A [a](for arsenic only), or EPA SW-846-7740 [a](for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

[78 FR 7201, Jan. 31, 2013]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the lowest hourly

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				average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests.
				(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b)	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.

		that sorbent		
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2emission rate	i. Establish a site-specific maximum SO_2emission rate operating limit according to § 63.7530(b)	(1) Data from SO_2CEMS and the HCl performance test	(a) You must collect the SO_2emissions data according to § 63.7525(m) during the most recent HCl performance tests.
				(b) The maximum SO_2emission rate is equal to the lowest hourly average SO_2emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the

				performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7203, Jan. 31, 2013]

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Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and

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	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes.
	b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2emissions using SO_2CEMS	a. Collecting the SO_2CEMS output data according to § 63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2CEMS emission rate to a level at or below the minimum hourly SO_2rate measured during the most recent HCl performance test according to § 63.7530.

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[78 FR 7204, Jan. 31, 2013]

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
	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, continuous opacity 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	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575

§ 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)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.

§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.

§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.

§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1

1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

[76 FR 15664, Mar. 21, 2011]

EDITORIAL NOTE: At 78 FR 7206, Jan. 31, 2013, Table 11 was added, effective Apr. 1, 2013. However Table 11 could not be added as a Table 11 is already in existence.

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel	a. Mercury	3.5E-06 lb per MMBtu of heat input	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
2. Units in all subcategories designed to burn solid fuel that combust at least	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling	Collect a minimum of 1 dscm per run.

10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis		average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
7. Stokers designed to burn biomass/bio-based solids	a. CO	560 ppm by volume on a dry basis corrected to 3	1 hr minimum sampling time.

		percent oxygen	
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
10. Fuel cells designed to burn biomass/bio-based solids	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters

			per run.
	c. Mercury	3.0E-07 lb per MMBtu of heat input	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
13. Units designed to burn liquid fuel located in non-continental States and territories	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.
14. Units designed to burn gas 2 (other) gases	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling	Collect a minimum of 1 dscm per run.

		average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr)	
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a]collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

[76 FR 15664, Mar. 21, 2011]

EDITORIAL NOTE: At 78 FR 7208, Jan. 31, 2013, Table 12 was added, effective Apr. 1, 2013. However, Table 12 could not be added as a Table 12 is already in existence.

Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before January 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM

			D6784 [b]collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable	2.0E-02 lb per MMBtu of heat	Collect a minimum of 2 dscm per

	PM (or TSM)	input; or (2.9E-05 lb per MMBtu of heat input)	run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07 [a]lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130 [a]ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis	1 hr minimum sampling time.

		corrected to 3 percent oxygen, 3-hour rolling average)	
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7210, Jan. 31, 2013]